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February 1, 2016

Via Hand Delivery

Ms. Lora W. Johnson
Clerk of Council
Council of the City of New Orleans
Room 1E09, City Hall
1300 Perdido Street
New Orleans, LA 70112

Re: *In Re*: Resolution Regarding Proposed Rulemaking to Establish Integrated Resource Planning Components and Reporting Requirements for Entergy New Orleans, Inc. (Docket No. UD-08-02)

Dear Ms. Johnson:

Pursuant to Council Resolution R-14-224, enclosed please find an original and three copies of Entergy New Orleans, Inc.'s ("ENO") Final 2015 Integrated Resource Plan ("IRP") Report, including a disk containing the Supplements 1-3, 5, and 7-11, and the Public Versions of Supplements 4 and 6. Please file an original and two copies into the record in the above-referenced matter, and return a date-stamped copy to our courier.

A copy of the Highly Sensitive versions of Supplements 4 and 6 have been designated "Highly Sensitive Protected Materials" and will be distributed under separate cover to authorized Reviewing Representatives pursuant to the Council's Official Protective Order adopted in Council Resolution R-07-432.

Thank you for your assistance with this matter.

Sincerely,

Timothy S. Cragin

TSC:pe
Enclosures
cc: Official Service List UD-08-02 *(via electronic mail)*

CERTIFICATE OF SERVICE
Docket No. UD-08-02

I hereby certify that I have this 1st day of February 2016, served the required number of copies of the foregoing report upon all other known parties of this proceeding, by: ☒ electronic mail, ☐ facsimile, ☐ overnight mail, ☒ hand delivery, and/or ☒ United States Postal Service, postage prepaid.

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New Orleans, Louisiana, this 1st day of February, 2016.

Timothy S. Cragin

Entergy New Orleans, Inc.

2015 Integrated Resource Plan

February 1, 2016

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EXECUTIVE SUMMARY

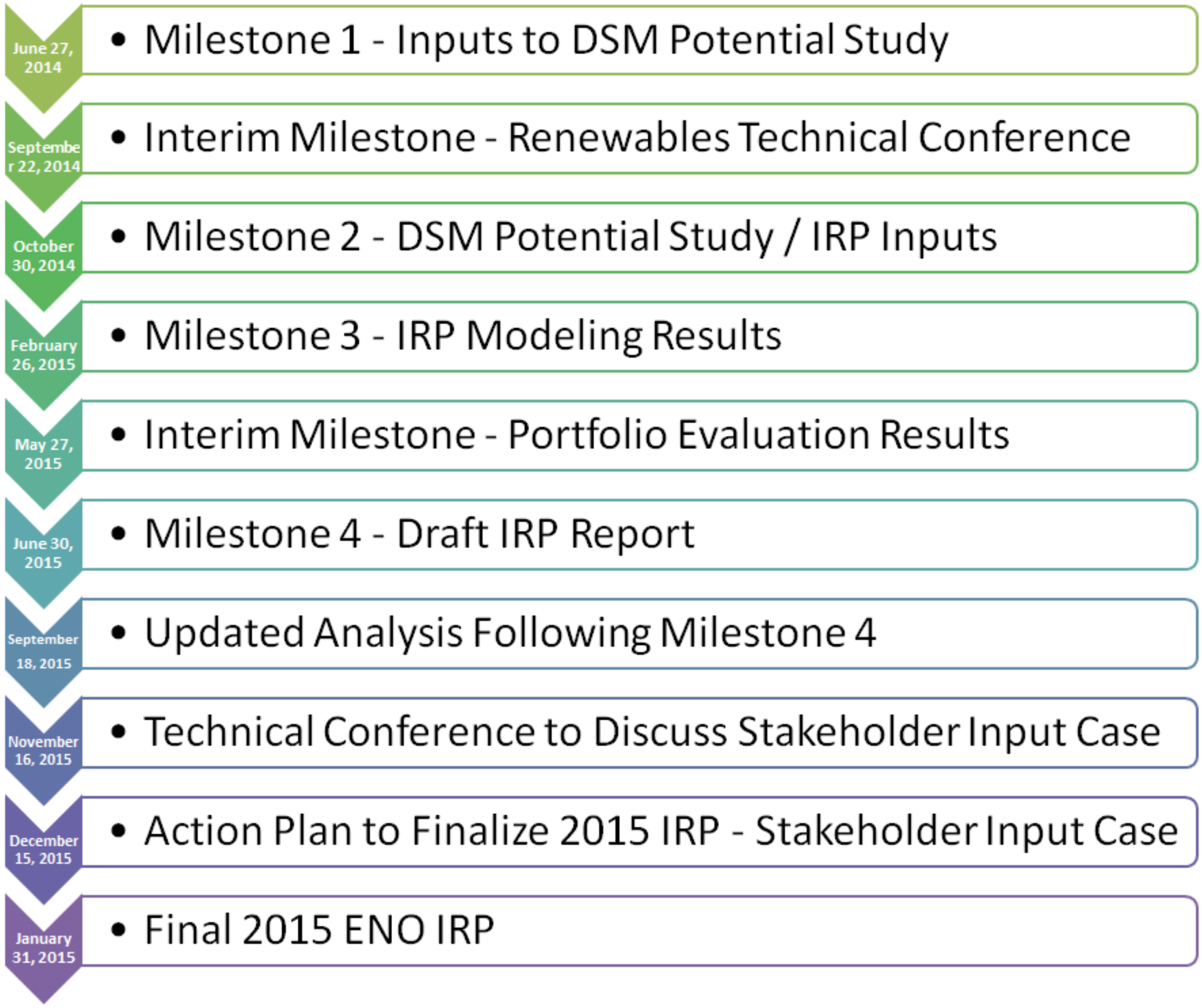
Introduction

This report documents the process and results of Entergy New Orleans, Inc.'s ("ENO") 2015 Integrated Resource Plan ("IRP"). This ENO 2015 IRP reflects the culmination of over 18 months of collaboration and analysis on the part of ENO and stakeholders including the public, intervenors and the legal and technical advisors ("Advisors") to the Council of the City of New Orleans ("Council"). The 2015 IRP reflects a balanced and reasonable resource plan for the coming 20 years (2015-2034)[1] that provides meaningful guidance and insight on the preferred types, combination and timing of changes to ENO's long-term resource portfolio that will contribute to ENO's ability to continue providing safe and reliable electric service to its customers at the lowest reasonable cost while mitigating risk. Inherent in the design of the ENO 2015 IRP Preferred Portfolio is the flexibility necessary to adapt to changing market, environmental and regulatory conditions. In developing the 2015 IRP, ENO's key areas of focus include addressing the planned deactivation of aging supply resources, and identifying the optimal combination of supply and demand-side resources necessary to maintain reliability, mitigate price uncertainty, promote fuel diversity and stability, and address environmental uncertainties.

In developing the 2015 IRP, ENO was guided by the process previously established by the Council for development of, and stakeholder input to, the ENO 2015 IRP in Resolution R-14-224, which requires a series of milestones be met with corresponding documentation, and provides for timely stakeholder input through contemporaneous technical meetings and Q&A sessions with the public and parties to the IRP proceeding. As shown in Figure 1, below, the process for the 2015 IRP consisted of four primary milestones, as well as 2 interim milestones. To address stakeholder and Advisor concerns, ENO agreed to perform additional analysis after Milestone 4 regarding changes to various input assumptions that occurred during the IRP process. To allow for this analysis to occur, ENO was granted an extension to file the final IRP by January 31, 2016. This additional analysis is discussed herein, where applicable, and is supported by a Demand-Side Management ("DSM") supplement and a Stakeholder Input Case supplement. The information provided in each supplement, along with the draft IRP, helped inform the development of the Final 2015 IRP Preferred Portfolio and corresponding Action Plan.

[1] At the request of stakeholders, additional analysis was performed using alternative assumptions for the years 2016-2035, the results of which are included in the Updated Assumptions supplement

Figure 1: IRP Milestones



Current Assessment

ENO is an integrated utility responsible for serving the electric and natural gas demands of Orleans Parish, Louisiana which includes the City of New Orleans. The City of New Orleans is located in a sub-region of the Amite South Planning Region, known as the Downstream of Gypsy ("DSG") area. DSG generally encompasses the area south of Lake Pontchartrain and east to the Gulf of Mexico.

<u>Supply-Side Resources</u>

As of the time of this filing, ENO's supply-side electric generation portfolio consists of approximately 1,318MW of long-term generation resources across a range of technologies and fuel types including nuclear, natural gas, as well as a small amount of hydro and coal. Currently, over half of ENO's generating capacity consists of legacy natural gas-fired generating units (Michoud Units 2 and 3); however, with the deactivation of Michoud Units 2 (239 MW) and 3 (542 MW) scheduled to occur in 2016, ENO's remaining resource portfolio will consist primarily of nuclear and combined-cycle gas turbine ("CCGT") resources which are projected to provide roughly half of ENO's capacity and energy needs. Additionally, subject to receipt of all applicable regulatory approvals ENO will secure an additional 510 MW of CCGT capacity and associated energy through the acquisition of Power Block 1 of the Union Power Station. As a result, the Preferred Portfolio reflects that ENO will meet its projected base load and core load-following needs with existing resources; however, as discussed in more detail in this report ENO will need additional resources to meet its projected peak capacity and reserve requirement.

<u>Demand-Side Resources</u>

Currently in its fifth year of existence, Energy Smart is a comprehensive utility-sponsored energy efficiency program available to all residents and businesses located in Orleans Parish. The plan underlying Energy Smart was developed by the Council, is administered by ENO, and implemented by CLEAResult. Funding for the first three years of Energy Smart was recovered from customers through ENO's electric rates. Program years 4-6 (April 1, 2014 – March 31, 2017) are being funded primarily by Rough Production Cost Equalization remedy payments received from other Entergy Operating Companies pursuant to prior decisions of the Federal Energy Regulatory Commission.

The initial phase of Energy Smart consisted of three consecutive annual program years lasting from April 2011 through March 2014. During those three years, Orleans Parish ratepayers saved over 52 million kWh of electricity[2] through a variety of cost-effective programs. Incentives were provided for energy efficient measures including, but not limited to, energy audits, direct install CFL bulbs, low flow fixtures, weatherization, HVAC, A/C Tune-ups and lighting. Program Year 4 was a continuation of the initial phase, offering the same programs and saving another 16,449,016 kWh.

Design of the Energy Smart energy efficiency programs begins with, and is informed by, ENO's long-term DSM Potential Studies undertaken in each Triennial IRP cycle. In evaluating the extent to which cost-effective DSM is achievable in New Orleans, the 2015 DSM Potential Study considered the results attained, and experiences learned, through previous years of Energy Smart. Similarly, in development of the second phase of Energy Smart (April 1, 2015 – March

[2] Average annual percent of sales from 2011-2014 was .34%.

31, 2017), the results of the 2012 IRP provided general guidance on the types of energy efficiency programs which were considered. This link between the IRP, and the design of DSM programs is expected to continue; however, there are differences between the results of long-term potential studies and the details of program design and implementation, and those differences are reasonable and to be expected.

Interruptible Load

In addition to Energy Smart, ENO's portfolio of demand-side resources includes interruptible load associated with a large industrial customer located in its service area. Subject to the terms of the customer's service agreement, ENO can call on the customer to reduce its electric use to reduce ENO's peak resource needs to help mitigate periods when demand could exceed available supply during certain contingency events. Importantly, this load is included in the calculation of ENO's long-term resource needs as a load-modifying resource and will be registered for participation in the Midcontinent Independent System Operator, Inc. ("MISO") Resource Adequacy process for the 2016 – 2017 planning year.

Advanced Metering Infrastructure

Entergy's regulated utilities are currently considering various future investments to modernize the distribution grid and more fully utilize new technologies. Such investments will provide benefits including improved grid resiliency, enhanced operations and communications, and new decision-making tools for customers. Among those investments is advanced metering infrastructure ("AMI"). Some benefits of AMI include enabling faster outage restoration during storm events thru more accurate real-time operations data as well as improved restoration planning and communications; providing customers with greater knowledge and control over their electric usage, which could enhance conservation; and facilitating more timely response to service inquiries, especially service connects and reconnects. AMI also provides a foundation upon which other investments to modernize the grid can be made. At this point, AMI continues to be analyzed and ENO plans to talk further with the City Council and its Advisors regarding potential future AMI investments.

Resource Need

The purpose of the IRP is to develop a long-range plan that is capable of meeting ENO's projected resource needs and support ENO's primary objective to continue providing safe and reliable service to ENO's customers at the lowest reasonable cost. In support of that objective, the 2015 ENO IRP identifies and evaluates a range of potential resource combinations from the available, cost-effective demand- and supply-side alternatives, and selects from those alternatives the optimal combination that results in the lowest reasonable cost while considering reliability and risk.

Although ENO's current supply and demand-side resource portfolio meets existing customer load requirements, new resources will be needed in the future to maintain reliability as load grows and aging supply resources are deactivated. The addition of load to ENO through the Algiers acquisition, which was finalized on September 1, 2015, only enhances ENO's need as the load in Algiers grows and aging resources allocated to ENO pursuant to the Algiers PPA deactivate. By the end of the twenty-year planning horizon, ENO is projected to need between 750 - 821 MW of new capacity resources[3]. This need is driven primarily by the planned deactivation of Michoud Units 2 and 3 in 2016. These units, which combine to provide approximately 780 MW of capacity, represent over half of ENO's generating capacity. Furthermore, by 2034 ENO's projected peak demand is expected to increase between 123 - 160 MW.[4]

Long-Term Achievable DSM Potential

For the 2015 IRP, ENO engaged the services of ICF International to assess the long-term market-achievable potential for DSM programs ("Potential Study") that could be deployed over the planning horizon. A comprehensive measure database that included 228 measure types and 1,056 measures in total was used to evaluate the market-achievable potential for DSM programs for ENO. Commercially available electric and gas measures covering each relevant savings opportunity within each end-use and sector were included.

Measures were then screened for cost-effectiveness using the measure Total Resource Cost (TRC) test. With few exceptions, only measures with a TRC test result of 1.0 or better were passed on to the next stage of the analysis. ICF's analysis found 814 measures to be cost effective. These economic measures are then mapped into programs. The program types are usually based on the set of existing programs offered in the service area plus additional programs for which there are cost-effective applicable measures. These additional programs are generally based on best practice designs. Based on the 814 cost-effective measures, the ICF Potential Study designed 24 programs to be assessed further in the IRP process. The Potential Study estimated the peak load, annual energy reduction, and program costs that result from a low, reference, and high level of spending on program incentives to participating customers.[5]

[3] Capacity need by 2035 in Stakeholder Input Case is approximately 901 MW

[4] Peak demand increase from 2016 to 2035 is approximately 167 MW in Stakeholder Input Case

[5] Program incentives are paid to participating customers, thereby reducing the customer's upfront cost and corresponding payback period for a given program.

Supply-Side Resource Alternatives

The IRP process considers a range of alternatives available to meet planning objectives, including the existing fleet of generating units, as well as new demand-side management and supply-side resource alternatives. As part of this process, a Technology Assessment was conducted to identify potential supply-side resource alternatives that may be technologically and economically suited to meet ENO's projected resource needs. The initial screening phase of the Technology Assessment reviewed the supply-side generation technology landscape to identify resource alternatives that merited more detailed analysis.[6] A list of the technologies selected for further more detailed evaluation in the IRP included:

I. Natural Gas Fired Technologies
   a. Combustion Turbine ("CT")
   b. Combined-Cycle Gas Turbine ("CCGT")
   c. Large scale aero-derivative CT
   d. Small scale aero-derivative CT
   e. Internal combustion engine

II. Nuclear
   a. Advanced boiling water reactor

III. Renewable Technologies
   a. Solar Photovoltaic ("PV") (fixed tilt and tracking)
   b. Wind (onshore)
   c. Biomass

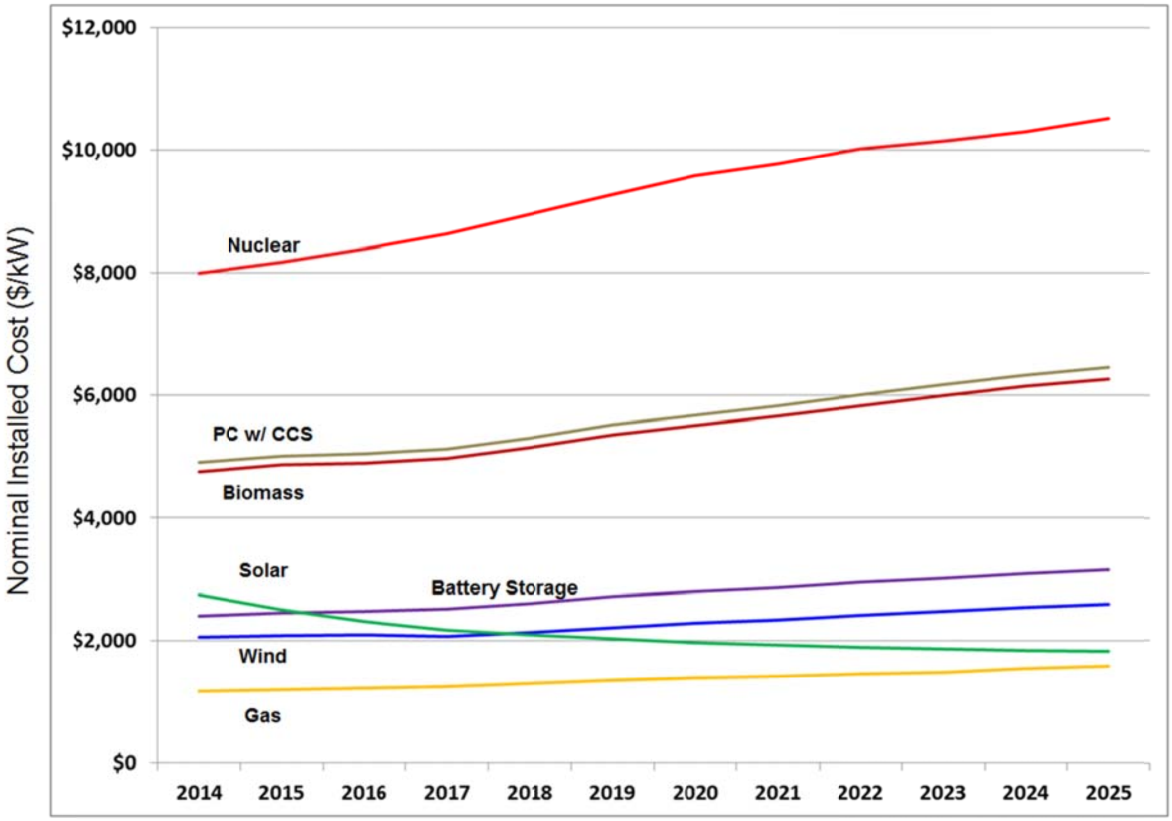
IV. Battery Storage

V. Pulverized Coal
   a. Supercritical pulverized coal with carbon capture and storage

During the initial phase, a number of resource alternatives were eliminated from further consideration based on a range of factors including technical maturity, stage of commercial development, and busbar economics. These resource alternatives will continue to be monitored for possible future development. A key output of the Technology Assessment was the projected levelized cost of the resource alternatives listed above. Figure 2 below summarizes the projected trend in installed costs of those alternatives selected for further evaluation in the 2015 IRP.

[6] See Technical Supplement 2 for the 2015 IRP Technology Assessment.

Figure 2: Projected Trend in Installed Cost of Supply-Side Resource Alternatives



Modeling

ENO used the AURORAxmp Electric Market Model ("AURORA"), a product of EPIS, Inc., in the development of this IRP. AURORA uses a linear optimization process and iterative calculations to find the optimal combination of resources to meet projected load-serving needs.

In development of the 2015 IRP, ENO designed four broad macroeconomic scenarios designed to capture a wide range of potential futures: Industrial Renaissance (Reference Case), Business Boom, Distributed Disruption, and Generation Shift. Assumptions differ for each case with respect to peak demand and load growth, fuel prices, and environmental costs. In addition to the four scenarios, ENO performed sensitivity analyses on the Industrial Renaissance Scenario to account for the effects of uncertainty in the future price of natural gas, potential for and extent of CO_2 regulation, and a combination of changes in the price of natural gas and CO_2. A further discussion of the AURORA modeling process is provided in Sections 2 and 4 of this report.[7]

Stakeholder Input

During the Council's process for development of the 2015 IRP, ENO received input from a broad range of stakeholders including members of the general public, intervenors in the IRP docket, and the Council's Advisors. ENO took all questions and comments received into consideration in producing this 2015 IRP and posted responses to questions and comments received to the public ENO IRP website. Although questions and comments received covered a wide range of issues, in general, there were several topics of particular and sometimes recurring interest in the 2015 IRP cycle that merit further consideration here. They include, but are not limited to ENO's:

1) Natural gas price forecast;
2) Capacity price forecast in MISO;
3) Cost assumptions for intermittent resources (*e.g.*, Onshore Wind and Solar PV);
4) Treatment of Distributed Generation;
5) Fuel diversity;
6) Carbon regulation;
7) Nuclear Relicensing; and
8) Public involvement

These issues are addressed in more detail in Section 2. For more information on the 2015 IRP process, including prior plans and more detailed information presented during the 2015 IRP cycle, please visit the ENO IRP website located at: www.entergy-neworleans.com/IRP/.

In response to stakeholder and Advisor concerns regarding dated assumptions used in the draft IRP, ENO agreed to perform additional production cost analysis using updated assumptions in support of the Final ENO 2015 IRP. The updated analysis is referred to herein as the "Stakeholder Input Case" scenario using contemporaneous information regarding load, commodity prices and generator status. Once the Stakeholder Input case was established, ENO ran six additional AURORA simulations for each of the portfolios previously evaluated in the draft IRP. The input assumptions and results related to the Stakeholder Input Case, including how they differed from the original assumptions and analyses, will be reported in each section where applicable. For additional details regarding the Stakeholder Input Case, please see the two supplements described below and attached with this final IRP report.

[7] In response to Stakeholder comments following Milestone 3, ENO filed a Modeling Process Workpaper which explains the AURORA modeling process in more detail.

DSM Supplement

The DSM supplement contains an overview of the following items:

- ENO's existing DSM programs
- Review of ICF Potential Study Methodology and Assumptions
- Sate of the Market for Demand Response
- Demand Response in MISO Markets
- DSM Breakeven Analysis and Program Selection

Stakeholder Input Case Supplement

The Stakeholder Input Case Supplement contains the following items:

- Updated forecast assumptions (natural gas, CO_2, renewable costs, etc.)
- Updated Load and Capability for all portfolios
- Updated Total Supply Cost for all portfolios
- Rate Effects for the Preferred Portfolio

Preferred Portfolio and Action Plan

The Final 2015 IRP has been developed to inform future resource procurement and implementation activities. The ENO Preferred Portfolio includes a combination of cost-effective demand- and supply-side resources that mitigate the risk of future uncertainty over a range of alternative potential future scenarios for energy and load growth, fuel prices, and environmental regulations. Importantly, the Preferred Portfolio is not prescriptive and includes the following key elements that will continue to be evaluated in future IRPs:

- ENO continues to meet the bulk of its reliability requirements from long-term capacity resources, whether owned assets or long-term power purchase agreements. The emphasis on long-term resources mitigates exposure to price volatility and ensures the availability of resources sufficient to meet long-term resource needs.
- All existing nuclear capacity, and the small amount of existing coal capacity, currently in ENO's portfolio continue operations throughout the planning horizon.[8]
- New supply resources, when needed come from peaking resources (*e.g.,* Combustion Turbines). As described in Sections 3 and 4 of the report, ENO is

[8] In the Stakeholder Input Case, Arkansas Nuclear One has a deactivation date of 2034, and White Bluff 1 and 2 have a deactivation assumption of 2026 and 2027 respectively.

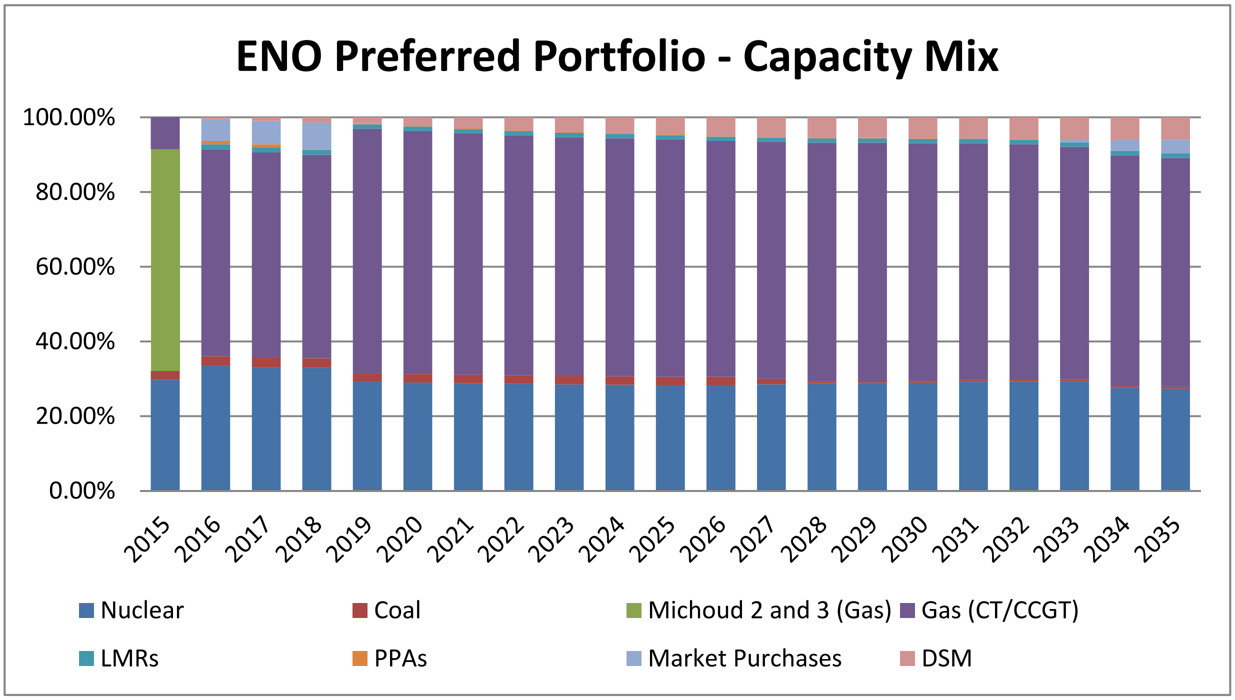
projected to need additional peaking resources as ENO's base load and core load-following needs are expected to be met by existing nuclear and CCGT resources and the planned addition of Union Power Block 1. Peaking resources such as Combustion Turbines are cost-effective, highly reliable and proven technology with minimal risk.

- While intermittent technologies such as renewable supply-side resources were not included in the Preferred Portfolio, ENO recognizes the potential fuel diversification and technology benefits such resources can contribute and has indicated in the Action Plan the intent to issue a Request for Proposals ("RFP") for renewable resources as described below. The Renewable RFP will provide valuable information on the availability and price for proven renewable technologies. ENO will continue to evaluate those and other alternatives for inclusion in future long-range plans, as the 2015 IRP does not preclude ENO from adopting those alternatives in future IRPs.
- The ENO Renewable RFP will be conducted during 2016 and request proposals for cost-effective renewable supply-side projects. This will provide a greater understanding of the cost and deliverability of renewable resources. A draft of the RFP is scheduled for release during the 2nd quarter of 2016, and will seek proposals for up to 20 MW of proven renewable energy technologies, with a preference for resources located in or near Orleans parish.
- In further support of the objective to evaluate the potential benefits of renewable technologies, ENO recently announced plans to conduct a 1 MW pilot project that will integrate solar PV generation and battery storage technology. The trend in the installed cost of photovoltaics and battery storage suggest a pilot project is prudent to help determine the degree to which battery storage can address the intermittent nature of photovoltaics, while simultaneously establishing a benchmark for utility-scale solar PV performance and cost/benefit in ENO's service area.
- The Preferred Portfolio includes 19 DSM (17 energy efficiency and 2 demand response) programs selected on the basis of their ability to cost-effectively reduce ENO's future resource needs. While this level of DSM is considered economically attractive, it presents ratemaking and policy issues that must be addressed in connection with the adoption of such programs. A variety of factors, many of which are highly uncertain, will affect the amount of DSM that can and will be achieved over the planning horizon, which factors would be addressed during the detailed implementation proceedings before the Council.[9]

Figure 3 below illustrates the mix of resources in the ENO Preferred Portfolio that contribute to meeting customer needs during the term of the planning horizon.

[9] Please refer to the DSM supplement for additional details.

Figure 3: ENO Preferred Portfolio (Stakeholder Input Case) - Capacity Mix



In support of the Preferred Portfolio, ENO has identified the key areas of focus and near-term steps in the Action Plan below that are necessary to continue moving forward on implementation of planned resources included in the Preferred Portfolio. Though the Preferred Portfolio calls for the addition of a peaking resource in 2019, the projected resource additions do not represent firm planning decisions. ENO will continue to closely monitor its current generation fleet and load requirements to ensure timely and cost-effective resource additions. The results of the modeling process, selection of the Preferred Portfolio, and a discussion of the Action Plan are provided in Sections 4 and 5.[10]

Customer Impact

Table 1 highlights the estimated impact of the Preferred Portfolio on an average ENO residential customer's electric bill.

[10] The Preferred Portfolio reflects assumptions used in the Stakeholder Input Case

Table 1: ENO Average Residential Customer Electric Bill (Preferred Portfolio)[11]

Projected ENO Residential Customer Bill and Energy Usage				
Customer Segment	Actual 2014 Usage (KWh/mo.)	Actual 2014 Average Monthly Bill	Projected 2035 Usage (KWh/mo.)	Projected 2035 Average Monthly bill
Residential (Legacy)	1,081	$109	1,332	$147
Residential (Algiers)	_	_	1,561	$149

The estimated typical bill effects associated with the cost to meet customer's needs through the Preferred Portfolio over the next two decades are modest. Over time, inflation in the broader economy tends to drive prices up for all goods and services, and in general the average annual growth rate in projected customer bills (reflected in the last column in Table 2) during the IRP planning horizon are expected to grow below inflation expectations.

Table 2: Rate Effects – ENO Preferred Portfolio (Stakeholder Input Case)

Projected ENO Average Monthly Customer Bill				
Customer Segment	2016	2026	2035	CAGR[12]
Residential (Legacy)	$110	$127	$147	1.5%
Commercial (Legacy)	$1,095	$1,111	$1,135	0.2%
Industrial (Legacy)	$1,302	$1,151	$1,009	(-1.3%)
Government (Legacy)	$3,377	$3,815	$4,096	1.0%
Residential (Algiers)	$100	$132	$149	2.0 %
Commercial (Algiers)	$628	$836	$922	1.9%
Industrial (Algiers)	$234	$348	$406	2.8%
Government (Algiers)	$1,282	$1,775	$2,050	2.4%

SECTION 1: PLANNING FRAMEWORK

ENO's planning process seeks to accomplish three broad objectives:

[11] Includes benefits associated with the optimal (cost-effective) level of DSM identified through the DSM Optimization.

[12] Compound Annual Growth Rate ("CAGR") measures the average annual rate of growth in typical customer bills over the planning horizon.

- To serve customers' power needs reliably;
- To do so at the lowest reasonable supply cost; and
- To mitigate the effects and the risk of production cost volatility resulting from fuel price and purchased power cost uncertainty, RTO-related charges such as congestion costs, and possible supply disruptions.

Objectives are measured from a customer perspective. That is, ENO's planning process seeks to design a portfolio of resources that reliably meets customer power needs at the lowest reasonable supply cost while considering risk.

In designing a portfolio to achieve the planning objectives, the process is guided by the following principles:

- *Reliability* – sufficient resources to meet customer peak demands with adequate reliability.

- *Base Load Production Costs* – low-cost base load resources to serve base load requirements, which are defined as the firm load level that is expected to be exceeded for at least 85% of all hours per year.

- *Load-Following Production Cost and Flexible Capability* – efficient, dispatchable, load-following resources to serve the time-varying load shape levels that are above the base load supply requirement, and also sufficient flexible capability to respond to factors such as load volatility caused by changes in weather.

- *Generation Portfolio Enhancement* – a generation portfolio that avoids an over-reliance on aging resources by accounting for factors such as current operating role, unit age, unit condition, historic and projected investment levels, and unit economics, and taking into consideration the manner in which MISO dispatches units.

- *Price Stability Risk Mitigation* – mitigation of the exposure to price volatility associated with uncertainties in fuel and purchased power costs.

- *Supply Diversity Risk Mitigation* – mitigation of the exposure to major supply disruptions that could occur from specific risks such as outages at a single generation facility.

Transmission and Distribution Planning

ENO's transmission planning ensures that the transmission system (1) remains compliant with applicable NERC Reliability Standards and related SERC and local planning criteria, and (2) is designed to efficiently and reliably deliver energy to end-use customers at the lowest reasonable cost. Since joining MISO, ENO plans its transmission system in accordance with the MISO Tariff. Expansion of, and enhancements to, transmission facilities must be planned well in advance of the need for such improvements given that regulatory, permitting processes and construction significantly extend the timeframe required to bring a transmission project to completion. Advanced planning requires that computer models be used to evaluate current and projected use of the bulk electric transmission system taking into account how those uses may change over time, generation and load forecasts, and transmission facilities already included in construction plan. On an annual basis, ENO's Transmission Planning Group performs analyses to determine the reliability and economic performance needs of ENO's portion of the interconnected transmission system. The projects developed are included in the Long Term Transmission Plan ("LTTP") for submission to the MISO Transmission Expansion Planning ("MTEP") process as part of a bottom-up planning process for MISO's consideration and review. The LTTP consists of transmission projects planned to be in-service in an ensuing 10-year planning period. The projects included in the LTTP serve several purposes: to serve specific customer needs, to provide economic benefit to customers, to meet NERC TPL reliability standards, to facilitate incremental block load additions, and to enable open access transmission service to be sold and generators to interconnect to the electric grid.

With regard to transmission planning aimed at providing economic benefit to customers, ENO has played, and will continue to play, an integral role in MISO's top-down regional economic planning process referred to as the Market Congestion Planning Study ("MCPS"), which is a part of the MTEP process. MISO's MCPS relies on the input of transmission owners and other stakeholders, both with regard to the assumptions and scenarios utilized in the analysis of proposed economic projects. Based on this stakeholder input, MISO evaluates the economic benefits of the submitted transmission projects, while ensuring continued reliability of the system. The intended result of the MCPS is a project(s) determined to be economically beneficial[13] to customers for consideration by the MISO Board of Directors for approval.

ENO has and continues to be actively involved in MISO's stakeholder processes to develop and finalize the assumptions and future scenarios proposed by MISO in the MCPS process for evaluation of projects proposed for consideration in MTEP15. ENOassessed the congestion on the transmission system in the MTEP15 Promod models and analyzed the economic benefits

[13] MISO determines cost-benefit by evaluating estimated production cost savings before and after the transmission upgrade adjusted for the fixed cost of the investment.

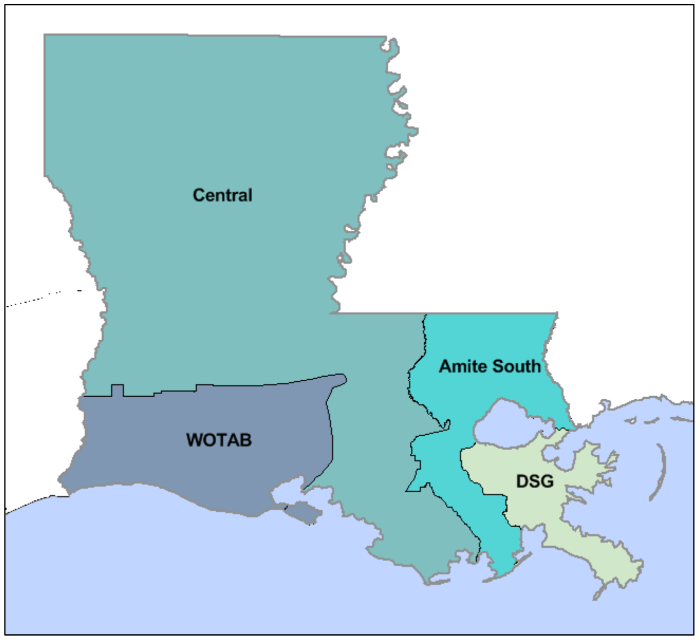
to ENO customers of candidate economic projects and also to satisfy the reliability requirements. Candidate transmission project ideas were due to MISO on June 19. Following the submittal of stakeholder projects and further economic analysis of those projects, MISO recommended transmission projects that meet MISO's economic benefits test to the MISO Board for approval. The MISO Board officially approved MTEP15 in December 2015. Out of the approved projects in Appendix A of the MTEP15 study, approximately 59 projects were located throughout the four states of the Entergy service footprint, with 3 projects planned for the ENO footprint.

While the distribution system is no less important than generation or transmission, unlike the transmission system, the distribution system is a local area system that functions to distribute power transmitted to the city and therefore is not a consideration in determining the most cost-effective way to access generation supplies necessary to meet customers' needs. However, ENO's distribution system is planned, operated and maintained as necessary to meet the needs of the city of New Orleans. The 2015 IRP assumes that the distribution system will continue to receive ongoing capital investment necessary to continue meeting those needs.

Area Planning

Although resource planning is performed with the goal of meeting planning objectives at the overall lowest reasonable cost, physical and operational factors dictate that regional reliability needs must be considered when planning for the reliable operation within the area. Thus, one aspect of the planning process is the development of planning studies to identify supply needs within specific geographic areas, and to evaluate supply options to meet those needs.

Figure 4: Map of Louisiana Planning Areas



For planning purposes, planning areas are determined based on characteristics of the electric system including the ability to transfer power between areas as defined by the available transfer capability, the location and amount of load, and the location and amount of generation. The region served by ENO is within the DSG sub-area of the Amite South planning area identified in Figure 4. The planning area and sub-area are described further below:

- Amite South – the area generally east of the Baton Rouge metropolitan area to the Mississippi state line, and the area south to the Gulf of Mexico.
    - Downstream of Gypsy ("DSG") – a sub-area encompassing the Southeast portion of Amite South, generally including the area down river of the Little Gypsy plant including metropolitan New Orleans south to the Gulf of Mexico.

Notwithstanding the termination of the Entergy System Agreement, as discussed in more detail below, area planning will continue to be an important part of ENO's long-term integrated resource planning process for the foreseeable future. The planning areas are a function of historical design and build-out of the bulk electric grid in the region as well as corresponding power flows on the grid.

Participation in MISO

ENO, along with its affiliate Entergy Operating Companies ("EOCs"), became market participants in MISO on December 19, 2013. MISO is a regional transmission organization

("RTO") allowing ENO access to a large structured market that enhances the resource alternatives available to meet ENO's customers' near-term power needs. Over the long-term, the availability and price of power in the MISO market is taken into consideration in developing ENO's resource strategy and portfolio design, however; ENO retains responsibility for providing safe and reliable service to its customers. Thus, the ENO 2015 IRP is designed to help ensure development of a long-term integrated resource plan for New Orleans that reflects that responsibility and balances the objective of minimizing the cost of service while considering factors that affect risk and reliability. Operations in MISO are key considerations in the development and modeling of the 2015 IRP. More detail on how ENO's participation in MISO is taken into consideration in developing the 2015 IRP is discussed briefly below and throughout the remainder of this report.

RESOURCE ADEQUACY REQUIREMENTS

As a load serving entity ("LSE") within MISO, ENO is responsible for maintaining sufficient generation capacity to meet the Planning Reserve Margin Requirement ("PRMR") set each year by MISO pursuant to its Tariff. Resource Adequacy is the process by which MISO ensures that participating LSEs meet those requirements.

Under MISO's Resource Adequacy process, MISO annually determines (by November 1 each year) the PRMR applicable to each Local Resource Zone ("LRZ") for the next planning year (June – May). LSEs are required to provide planning resource credits for generation or demand-side capacity resources to meet their forecasted peak load coincident with the MISO peak load plus the PRMR established by MISO. Planning resource credits are measured by unforced capacity (installed capacity multiplied by an appropriate forced outage rate). The annual PRMR for the LRZ 9 (which includes ENO), as determined by MISO, sets the minimum PRMR[14] that ENO must meet. MISO does not calculate a long-term planning reserve requirement, so for purposes of long-term planning, ENO has determined that a 12% reserve margin based on installed capacity ratings and forecasted (non-coincident) firm peak load is reasonable and adequate to cover MISO's Resource Adequacy requirements and uncertainties such as MISO's future required reserve margins, generator unit forced outage rates, and forecasted peak load coincidence factors.[15]

[14] In MISO, Resource Adequacy PRMR is expressed based on unforced capacity ratings and MISO System coincident peak load. Traditionally, ENO and other LSEs have stated planning reserve requirements based on installed capacity ratings and forecasted (non-coincident) peak load.

[15] It can be shown mathematically that the planning reserve margin determined by using unforced capacity and coincident peak load is roughly equivalent to the planning reserve margin determined by using installed capacity and non-coincident peak load.

Entergy System Agreement

The electric generation and bulk transmission facilities of the EOCs party to the Entergy System Agreement currently are planned and operated on an integrated, coordinated basis as a single electric system and are referred to collectively as the "Entergy System."

The EOCs that party to the System Agreement are ENO, Entergy Gulf States Louisiana, L.L.C. ("EGSL"), Entergy Louisiana LLC ("ELL"), and Entergy Texas, Inc. ("ETI").[16] As provided for pursuant to the terms for exit from the System Agreement, ETI provided notice that it would terminate its participation on October 18, 2018.[17] On February 14, 2014, EGSL and ELL provided written notice to the other participating EOCs of the termination of their participation in the System Agreement. In light of those decisions, the 2015 IRP was prepared assuming that ENO will no longer participate in the System Agreement as of February 14, 2019[18]. Prior to and during the 2015 IRP cycle, the retail regulators of EGSL, ELL, ETI and ENO were engaged in settlement discussions with the EOCs party to the System Agreement for terms necessary to terminate the System Agreement early. Subsequent to those discussions, the parties reached agreement and approved a settlement agreement to terminate the System Agreement on August 31, 2016. On December 29, 2015, the FERC approved the settlement agreement. Although ENO could not have known the outcome of settlement discussions at the time assumptions were established for the 2015 IRP cycle, the reasonable and still appropriate assumption was made that current resource planning efforts acknowledge that stand-alone operations are on the front-end of the 2015 IRP planning horizon, thus ENO should begin taking steps now to account for the corresponding effects post-termination of the System Agreement.

SECTION 2: ASSUMPTIONS

Technology Assessment

The IRP process considers a range of alternatives available to meet the planning objectives, including the existing fleet of generating units, as well as new DSM and supply-side resource alternatives. As part of this process, a Technology Assessment was prepared to identify potential supply-side resource alternatives that may be technologically and economically suited to meet projected resource needs. The initial screening phase of the Technology Assessment

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[16] Entergy Arkansas, Inc. ("EAI") and Entergy Mississippi, Inc. ("EMI"), also EOCs, terminated their participation in the System Agreement effective December 18, 2013 and November 7, 2015, respectively.

[17] Subject to the FERC's ruling in Docket No. ER14-75-000 which is the FERC proceeding filed to amend the notice provisions of Section 1.01 of the System Agreement.

[18] EGSL's and ELL's notice would be effective February 14, 2019 or such other date consistent with the FERC's ruling in Docket No. ER14-75-000, effectively leaving ENO as the only remaining Operating Company in the System Agreement. However, a settlement agreement was reached and approved by FERC for early termination of the System Agreement.

reviewed the supply-side generation technology landscape to identify resource alternatives that merited more detailed analysis. A list of the technologies selected for further more detailed evaluation in the IRP included:

I. Natural Gas Fired Technologies
   a. Combustion Turbine (“CT”)
   b. Combined-Cycle Gas Turbine (“CCGT”)
   c. Large scale aero-derivative CT
   d. Small scale aero-derivative CT
   e. Internal combustion engine

II. Nuclear
   a. Advanced boiling water reactor

III. Renewable Technologies
   a. Solar PV (fixed tilt and tracking)
   b. Onshore Wind
   c. Biomass

IV. Battery Storage

V. Pulverized Coal
   a. Supercritical pulverized coal with carbon capture and storage

Upon completion of the screening level analysis, more detailed analysis (including revenue requirements modeling of remaining resource alternatives) was conducted across a range of operating roles and under a range of input assumptions. The analysis resulted in the following conclusions:

- Among conventional generation resource alternatives, CCGT and CT technologies are the most cost-effective. The gas-fired alternatives are economically attractive across a range of assumptions concerning operations and input costs.
- New nuclear and new coal alternatives are not cost-effective near-term options relative to gas-fired technology. The low price of gas and the uncertainties around emissions regulation make coal technologies unattractive. Nuclear is currently unattractive due to both capital and regulatory requirements.
- Despite recent declines in the installed cost and improvements in the operational viability of renewable generation alternatives, they are still less cost-effective when compared to CCGT and CT alternatives due primarily to:
  - Declines in the long-term outlook for natural gas prices brought on by the shale gas boom; and

- The uncertain near-term outlook for regulation of CO_2 emissions.

- Among renewable generation alternatives, wind and solar are the most likely to become cost competitive with conventional alternatives. However, uncertainties with respect to capacity credit granted to intermittent resources by MISO, and the extent and timing of CO_2 regulations likely will affect the competitiveness of renewable resource alternatives.

  - MISO determines the capacity value for wind generation based on a probabilistic analytical approach. The application of this approach resulted in a capacity value of approximately 14.1% for wind resource during the 2014-15 MISO planning year. In ENO's Technology Assessment, wind was assessed a capacity match-up cost to reflect the fact that wind receives partial capacity value in MISO due to its intermittent nature. *The capacity match-up is only used in the screening analysis of supply-side resources, and is not considered in any further analysis in the ENO IRP.* Furthermore, ENO's service area is not favorable for wind generation. The transmission cost to serve load with wind power from remote resources will further erode the economics of wind as compared to conventional supply-side resource alternatives.

  - In MISO, solar resources currently receive capacity credit equal to 25% of their nameplate (AC) rating within the first year of operation. Once operational, solar-powered resources must submit all operating data for the prior summer with a minimum of 30 consecutive days to obtain capacity that more closely aligns to operational capability. Thus, MISO grants capacity credit for solar resources on a case by case basis, which creates uncertainty for purposes of planning. Despite this uncertainty, ENO assumed a reasonable 25% capacity value for solar resources in its service area for further evaluation in the 2015 IRP.

Table 3 summarizes the results of the Technology Assessment for a number of resource alternatives.

Table 3: 2014 Technology Sensitivity Assessment

Based on Generic Cost of Capital[19]		No CO_2 (Lifecycle Levelized $/MWh)			CO_2 Beginning 2023 (Lifecycle Levelized $/MWh)		
Technology	Capacity Factor[20]	Reference Fuel	High Fuel	Low Fuel	Reference Fuel	High Fuel	Low Fuel
F Frame CT	10%	$198	$224	$179	$204	$230	$184
F Frame CT w/ Selective Catalytic Reduction	20%	$141	$167	$121	$146	$173	$126
E Frame CT	10%	$240	$274	$215	$247	$281	$222
Large Aeroderivative CT	40%	$108	$131	$91	$113	$136	$95
Small Aeroderivative CT	40%	$125	$150	$106	$130	$156	$112
Internal Combustion	40%	$115	$137	$99	$120	$141	$104
2x1 F Frame CCGT	65%	$79	$97	$67	$83	$100	$70
2x1 F Frame CCGT w/ Supplemental	65%	$75	$93	$61	$78	$97	$65
2x1 G Frame CCGT	65%	$76	$93	$63	$79	$96	$67
2x1 G Frame CCGT w/ Supplemental	65%	$72	$90	$59	$76	$94	$63
1x1 F Frame CCGT	65%	$82	$100	$69	$86	$104	$73
1x1 J Frame CCGT	65%	$73	$90	$61	$77	$93	$65
1x1 J Frame CCGT w/ Supplemental	65%	$72	$132	$59	$76	$136	$63
Pulverized Coal w/ Carbon Capturing Sequestration	85%	$163	$230	$94	$165	$232	$96
Biomass	85%	$175	$321	$142	$175	$321	$142
Nuclear	90%	$157	$169	$157	$157	$169	$157
Wind[21]	34%	$109	$109	$109	$109	$109	$109
Wind w/ Production Tax Credit	34%	$102	$102	$102	$102	$102	$102
Solar PV (fixed tilt)[22]	18%	$190	$190	$190	$190	$190	$190
Solar PV (tracking)[23]	21%	$179	$179	$179	$179	$179	$179
Battery Storage[24]	20%	$217	$217	$217	$217	$217	$217

[19] A general discount rate (7.656%) was used in order to accurately model these resources in the Market Modeling stage of the IRP.
[20] Assumption used to calculate life cycle resource cost.
[21] Includes capacity match-up cost of $18.76/MWh due to wind's 14.1% capacity credit in MISO, which cost was not assessed in the production cost modeling.
[22] Includes capacity match-up cost of $30.93/MWh assuming a 25.0% capacity credit in MISO, which cost was not assessed in the production cost modeling.
[23] Includes capacity match-up cost of $26.51/MWh assuming a 25.0% capacity credit in MISO, which cost was not assessed in the production cost modeling.
[24] Includes cost of $25/MWh required to charge batteries.

Long-Term Achievable Demand Side Management Potential

For the 2015 IRP, ENO engaged the services of ICF International to assess the market-achievable potential for DSM programs that could be deployed over the planning horizon. A comprehensive measure database that included 228 measure types and 1,056 measures in total was used to evaluate the market-achievable potential for DSM programs for ENO. Commercially available electric and gas measures covering each relevant savings opportunity within each end use and sector were included.

Measures were then screened for cost-effectiveness using the measure Total Resource Cost (TRC) test. With few exceptions, only measures with a TRC test result of 1.0 or better were passed on to the next stage of the analysis. ICF's analysis found 814 measures to be cost effective. These economic measures are then mapped into programs. The program types are usually based on the set of existing programs offered in the service area plus additional programs for which there are cost-effective applicable measures. These additional programs are usually based on best practice designs. Based on the 814 cost-effective measures, the ICF Potential Study designed 24 programs to be assessed further in the IRP process.

The Potential Study estimated the peak load, annual energy reduction, and program costs that result from a low, reference, and high level of spending on program incentives. The reference investment level estimate of DSM potential indicates approximately 112 MW of peak demand reduction could be achieved by 2034 if ENO's investment in the 24 DSM programs was sustained for a 20-year period. For the purpose of DSM modeling in the IRP, ENO selected the incentive level for each program with the highest TRC ratio. This resulted in a range of incentive levels modeled.

The methodology of the Potential Study was consistent with ENO's primary objective to identify cost-effective DSM alternatives available to meet customers' needs. Furthermore, the MISO Tariff outlines that energy efficiency resources must be fully implemented at all times during the planning year, without any requirement of dispatch. Examples of these resources include, but are not limited to, efficient lighting and appliances, and building insulation. Demand response resources are defined as resources that allow the ability of a market participant to reduce its electric consumption, with either discretely interruptible or continuously controllable loads, in response to an instruction resource from MISO. The demand response and energy efficiency programs identified and analyzed in the Potential Study were consistent with MISO's requirements.

DSM program costs utilized in the IRP include incentives paid to participants and program delivery costs such as marketing, training, and program administration. Program delivery costs were estimated to reflect average annual costs over the 20 year planning horizon of the DSM

Potential Study. The costs reflect an assumption that over the planning horizon, program efficiencies will be achieved resulting in lower expected costs. That is, as experience is gained with current and future programs, actual cost may decrease over time. As such, actual near-term costs associated with implementation of current and future programs may be higher than the assumptions used to determine the optimal cost-effective level identified in ENO's Preferred Portfolio. Therefore, future DSM program goals and implementation plans should reflect this uncertainty.

Natural Gas Price Forecast

System Planning and Operations[25] ("SPO") prepared the natural gas price forecast[26] used in the 2015 IRP. The near term portion of the natural gas forecast is based on NYMEX Henry Hub forward prices, which serve as an indicator of market expectations of future prices. Because the NYMEX futures market becomes increasingly illiquid as the time horizon increases, NYMEX forward prices are not a reliable predictor of future prices in the long-term. Due to this uncertainty, SPO prepares a long term point-of-view ("POV") regarding future natural gas prices utilizing a number of independent expert consultant forecasts to determine an industry consensus regarding long-term prices.

The long-term natural gas forecast used in the IRP includes sensitivities for high and low gas prices to support analysis across a range of future scenarios. In developing high and low gas price POVs, SPO utilizes several proprietary independent expert consultant forecasts, as well as publicly available information, to determine long term price consensus. The long-term gas price forecast used in the 2015 IRP is shown in the table below.

[25] System Planning and Operations is a department within Entergy Services, Inc. ("ESI") tasked with: (1) the procurement of fossil fuel and purchased power, and (2) the planning and procuring of additional resources required to provide reliable and economic electric service to the EOCs' customers. SPO also is responsible for carrying out the directives of the Operating Committee and the daily administration of aspects of the Entergy System Agreement not related to transmission.
[26] The forecast was prepared from the July 2014 gas price forecast.

Table 4: Long-Term Henry Hub Natural Gas Price Forecasts

Henry Hub Natural Gas Prices						
	Nominal $/MMBtu			Real 2014$/MMBtu		
	Low	Reference	High	Low	Reference	High
Real Levelized'[27] (2015-2034)	$4.57	$5.77	$9.72	$3.84	$4.87	$8.17
Average (2015-2034)	$4.82	$6.28	$10.79	$3.66	$5.00	$8.08
20-Year CAGR	2.5%	3.1%	6.2%	0.4%	1.0%	4.1%

CO_2 Assumptions

At this time, it is not possible to predict with any degree of certainty whether or the extent to which the Clean Power Plan will survive the substantial litigation already filed against the EPA since issuing the final rule in August 2015. In order to consider the effects of this uncertainty on resource choice and portfolio design, the IRP process evaluated the effect of CO_2 regulation *by analyzing a range of projected CO_2 cost outcomes*. The reference case assumes that CO_2 legislation does not occur over the 20-year planning horizon. The mid case assumes that a cap and trade program starts in 2023 with an emission allowance cost of $7.54/U.S. ton and a 2015-2034 levelized cost in 2014$ of $6.83/U.S. ton.[28] The high case assumes that a cap and trade program starts in 2023 at $22.84/U.S. ton with a 2015-2034 levelized cost in 2014$ of $14.61/U.S. ton. Importantly, the Stakeholder Input Case includes the current POV mid case for CO_2 prices. By evaluating a range of potential outcomes, the IRP is better informed regarding the impact that the extent and timing of CO_2 regulation can have on the optimal mix of resources.

Market Modeling

AURORA MODEL

The development of the IRP relied on the AURORA Electric Market Model to simulate market operations and produce a long-term forecast of the revenues and cost of energy procurement for ENO in MISO.[29]

[27] "Real levelized" prices refer to the price in 2014$ where the NPV of that price grown with inflation over the 2015-2034 period would equal the NPV of levelized nominal prices over the 2015-2034 period.
[28] Includes a discount rate of 6.93%.
[29] The AURORA model replaces the PROMOD IV and PROSYM models that ENO previously used.

AURORA[30] is a production cost model and resource capacity expansion optimization tool that uses projected market economics to determine the optimal long-term resource portfolio under varying future conditions including fuel prices, available generation technologies, environmental constraints and future demand forecasts. AURORA estimates price and dispatch using hourly demands and individual resource-operating characteristics in a transmission-constrained, chronological dispatch algorithm. The optimization process within AURORA identifies the set of resources among existing and potential future demand- and supply-side resources with the highest and lowest market values to produce economically consistent capacity expansion. AURORA chooses from new resource alternatives based on the net real levelized values per MW ("RLV/MW") of hourly market values and compares those values to existing resources in an iterative process to optimize the set of resources.

SCENARIOS

The 2015 ENO IRP and corresponding analyses were built on four scenarios designed to assess alternative portfolios across a range of potential future outcomes. The four scenarios are:

- *Industrial Renaissance (Reference)* – Assumes the U.S. energy market continues to grow with reference fuel prices. Current fuel prices drive load growth and economic opportunity in the region. The Industrial Renaissance scenario assumes reference load, reference gas and no CO_2 costs.

- *Business Boom* – Assumes the U.S. energy boom continues with low gas and coal prices. Low fuel prices drive high load growth. A modest CO_2 tax or cap and trade program is implemented beginning in 2023.

- *Distributed Disruption* – Assumes states continue to support distributed generation. Consumers and businesses have a greater interest in installing distributed generation, which leads to a decrease in energy demand at the customer's meter. Overall economic conditions are steady with moderate GDP growth, which enables investment in energy infrastructure. However, natural gas prices are driven higher by EPA regulation of hydraulic fracturing. Congress or the EPA also implements a moderate CO_2 tax or cap and trade program.

[30] The AURORA model was selected for the IRP and other analytic work after an extensive analysis of electricity simulation tools available in the marketplace. AURORA is capable of supporting a variety of resource planning activities and is well suited for scenario modeling and risk assessment modeling. It is widely used by load serving entities, consultants, and independent power producers.

- *Generation Shift* – Assumes government policy and public interest drive support for government subsidies for renewable generation and strict rules on CO_2 emissions. High natural gas exports and more coal exports lead to higher fuel prices.

Each scenario was modeled in AURORA. The resulting market modeling, which included projected power prices, provided a basis for assessing the economics of long-term (twenty years) resource portfolio alternatives.

Table 5: Summary of Key Scenario Assumptions

Summary of Key Scenario Assumptions				
	Industrial Renaissance (Ref. Case)	**Business Boom**	**Distributed Disruption**	**Generation Shift**
Electricity CAGR (Energy GWh)[31]	~1.0%	~1.0%	~0.40%	~0.80%
Peak Load Growth CAGR	~0.7%	~0.7%	~0.7%	~0.7%
Henry Hub Natural Gas Price ($/MMBtu)	Reference Case ($4.87 levelized 2014$)	Low Case ($3.84 levelized 2014$)	Reference Case ($4.87 levelized 2014$)	High Case ($8.18 levelized 2014$)
CO_2 Price ($/U.S. ton)	Low Case: None	Cap and trade starts in 2023 $6.83 levelized 2014$	Cap and trade starts in 2023 $6.83 levelized 2014$	Cap and trade starts in 2023 $14.61 levelized 2014$

Stakeholder Input

During the Council's process for development of the 2015 IRP, ENO received input from a broad range of stakeholders including members of the general public, interveners in the IRP docket, and the Council's Advisors. ENO took all questions and comments received into consideration in producing this 2015 IRP and posted responses to questions and comments received from the public to the ENO IRP website. Although questions and comments received covered a wide range of issues, in general, there were several topics of particular, and sometimes recurring, interest in the 2015 IRP cycle that merit further consideration here. They include, but are not limited to ENO's:

1) Natural gas price forecast;

[31] All compound annual growth rates ("CAGRs") in this table: 2015-2034 (20 Years) for the market modeled in AURORA.

2) Capacity price forecast in MISO;
3) Cost assumptions for intermittent resources (e.g. Wind and Solar PV);
4) Treatment of Distributed Generation;
5) Fuel diversity;
6) Carbon regulation;
7) Nuclear Relicensing; and
8) Public involvement

During the development of the IRP, ENO was required to provide information regarding its input assumptions to the IRP very early on in the Council's process. In order to maintain the integrity of the Council's process, ENO complied with those requirements and solicited feedback from the public and intervenors on those assumptions as provided for by the Council. Unfortunately, much of the input ENO received regarding the input assumptions was not received until after the first 2 milestones. Notwithstanding, to reflect ENO's consideration of the input received on these key issues, a brief summary of each is provided below.

NATURAL GAS PRICE FORECAST

Regarding the IRP forecast of long-term natural gas prices, ENO received comments questioning the IRP forecast as too low, as well as too high. While the current outlook for natural gas prices is lower than the gas price forecast used in the 2015 IRP, the IRP Low Forecast is in line with current gas prices. Moreover, in the IRP process, each portfolio was assessed with each gas price forecast (low, reference, and high) to capture the impact of gas price fluctuations over the planning horizon. As a final step, ENO used the most current gas price forecast in the Stakeholder Input Case.

CAPACITY PRICE FORECAST IN MISO

Regarding ENO's projected capacity price curve used in the calculation of avoided costs associated with investing in demand-side resources, the auction clearing price for MISO Local Resource Zones 8 and 9 settled at $1.20/kW-yr. in the 2015/2016 Planning Resource Auction. These results were concurrent with the corresponding portion of ENO's capacity price projections used in the 2015 IRP.

COST ASSUMPTIONS FOR INTERMITTENT RESOURCES (*E.G.*, WIND AND SOLAR PV)

The Technology Assessment indicates that solar costs are likely to decline over the next five years; however, wind cost and performance are not expected to materially improve or decline over this time period. If wind and solar cost and performance improve more than expected in this IRP, then future IRPs will capture that.

The IRP seeks to identify generation technologies that are technologically mature and could reasonably be expected to be operational in or around ENO's regulated service area consistent with the timing of projected resource needs. In the detailed modeling phase of the 2015 IRP, ENO assumed a 34% capacity factor assumption for wind resources that could be developed in or around the Entergy regulated service areas. In response, ENO received comments that the cost assumptions for wind in the 2015 IRP were significantly above recent transactions for utility scale wind resources across the U.S.

Notwithstanding, as a member of MISO, ENO is required to adhere to MISO's capacity values for wind, which is 14.1% as outlined in MISO's Resource Adequacy Tariff (Module E) and Resource Adequacy Business Practice Manual. As such, in the IRP a capacity "match up" reflects the fact that wind receives partial capacity value in MISO due to wind's intermittent nature. Importantly, the capacity match-up is only used in the screening analysis of supply-side resources in the Technology Assessment. When modeled in AURORA, wind is evaluated without the capacity match up relative to other resources. For example, in the Technology Assessment ENO reflected a Levelized Cost of Electricity ("LCOE") for wind resources ranging from \$102 - \$115/MWh (nominal \$2014), which includes a match-up cost assumption of \$18.76/MWh. In contrast, in the detailed modeling phase of the 2015 IRP where AURORA determines the optimal combination of demand- and supply-side resources through an iterative process, ENO did not include the match-up cost.

TREATMENT OF DISTRIBUTED GENERATION

With respect to the treatment of Distributed Generating ("DG") resources in the context of a long-term IRP, ENO received comments and questions pertaining to the appropriateness of the methodology used in the IRP as compared to alternative methodologies. In the 2015 IRP, ENO accounted for the effects of the explosive growth in residential rooftop Solar PV, a type of DG, in New Orleans through a forecasted reduction in ENO's load. Although there are alternative methods to account for DG in the planning process, ENO believes accounting for them on the demand-side through a reduction to the load forecast appropriately recognizes that they are behind the customer's meter and require the customer to make the investment decision, neither of which are under ENO's control. Moreover, it is ENO's position that while state and federal tax incentives available to rooftop Solar PV in Louisiana, and current net metering policy in New Orleans, have combined to drive the growth in residential rooftop Solar PV in New Orleans; Such growth should not be construed as suggesting that DG resources are cost-effective alternatives to central-station utility-scale generation capable of achieving significant economies of scale resulting in lower average installation and operating costs. The state and federal tax incentives still represent a cost that must be factored into the Council's decision criteria regarding the need to specifically address the policy for treatment of DG in the planning process, as well as future net metering policy for New Orleans under consideration in Council Docket No. UD-13-02. ENO's recently announced Solar Pilot will establish a benchmark of the capabilities and operational costs for utility-scale solar and integrated battery storage in New Orleans. The Solar Pilot is a reasonable first step to ensure a balanced approach to the adoption of intermittent technologies that will help inform future IRPs.

FUEL DIVERSITY

A key objective of the 2015 IRP is to design a Preferred Portfolio that mitigates risk of uncertain future supply costs such as the price of natural gas. This key uncertainty is addressed in 2 ways. First, ENO establishes a basis for evaluating the fuel mix of the existing portfolio of resources by benchmarking the amount of capacity and energy sourced from each fuel type (*e.g.*, natural gas, nuclear, coal, etc.). In Section 3 additional details are provided on the current and projected fuel mix of ENO's existing portfolio before and after deactivation of the Michoud units. As discussed in more detail in Section 3, ENO's existing portfolio before and after the planned deactivation of the Michoud units results in a balanced fuel mix among gas, nuclear and coal on an energy basis. Whereas ENO relies on the Michoud units for a significant amount of capacity, those resources do not contribute an equivalent amount of energy, thus following their planned deactivation the fuel mix of ENO's energy requirements will remain balanced with room for some amount of modern, efficient and reliable gas-fired replacement resources as discussed in Section 3.

Second, the IRP gas price forecast is developed with a reference, high and low case to capture a range of future price outcomes. The gas price forecasts are then used to evaluate the alternative portfolios in each of the four macroeconomic scenarios developed for the IRP. In this way, ENO assesses the range of potential impacts of higher and lower gas prices on each of the alternative portfolios and the corresponding total supply costs to ENO's customers.

Many of the comments ENO received regarding fuel diversity centered around the notion that ENO is already over-exposed to natural gas fired resources, thus the addition of new gas-fired resources to ENO's portfolio will only exacerbate that issue. To the contrary, as discussed in Section 3 below, while ENO's portfolio consists of a significant amount of gas-fired capacity, those resources do not contribute an equivalent amount of energy, thus leaving room for gas-fired replacement resources following their planned deactivation. Moreover, those same comments suggested that incorporation of renewable resources would reduce the need to rely on gas-fired resources; however, as explained in the Cost Assumptions for Renewables section above, because renewable resources like wind and solar are intermittent neither MISO nor ENO can rely on those resources exclusively, and precisely because renewables such as wind and solar do not allow ENO to avoid an equivalent amount of conventional supply-side resources, the capacity match-up cost should be taken into consideration when evaluating the appropriateness of adopting renewables. A simple example is that if ENO needs 100 MW of resources, if it wanted to rely exclusively on renewables such as wind and solar, because they are intermittent ENO would have to add approximately 714 MW of wind resources or 400 MW of solar resources to provide a comparable amount of capacity as provided by a conventional supply-side resource such as CCGT or CT. Even in that scenario, precisely because those resources are intermittent ENO may not avoid the need to carry additional reserves to ensure proper commitment and dispatch necessary to maintain reliability.

CARBON REGULATION

Regarding the assumptions around regulation of CO_2, ENO received comments raising concerns that the company should assume CO_2 regulation in all of the IRP scenarios. In the IRP, ENO evaluated a range of CO_2 price assumptions in the IRP across the four scenarios to reflect the uncertain likelihood, extent and timing of CO_2 regulation. Moreover, the sensitivity analysis evaluates the effects of different CO_2 prices for each scenario. <u>*ENO believes it would be imprudent to assume CO_2 regulation in all of the IRP scenarios, as that would effectively assume that there is no uncertainty regarding the likelihood, extent and timing of CO_2 regulation, and more importantly, that ENO's customers should pay for CO_2 regulation regardless of whether regulation actually occurs*</u>. Notwithstanding, ENO included the current POV mid case CO_2 in the Stakeholder Input Case.

NUCLEAR RELICENSING

Nuclear resources require license renewals to extend their operational lifetime. All of the nuclear resources in ENO's portfolio have received, or are currently in the process of, seeking operating license renewals. License extensions for Arkansas Nuclear One Units 1 and 2 have been approved by the Nuclear Regulatory Commission ("NRC") and thus are licensed to operate through May 2034 and July 2038, respectively. Grand Gulf Nuclear Station has filed its license renewal application, which is currently under review by the NRC. The license renewal application for River Bend Nuclear Station is expected to be filed in the 1st quarter of 2017. License renewal for nuclear resources is estimated to cost approximately $20-$25M over a 5 year timeline per unit, not including major component refurbishment or replacement. Therefore, relicensing the nuclear units in ENO's portfolio provides for the continuation of a low cost alternative for base load capacity and energy.

PUBLIC INVOLVEMENT

Pursuant to the Council's process for the 2015 IRP, ENO is required to seek input from the public at each of 4 milestones. As a part of that process, the Council requires ENO to provide public notice no later than 30 days before any public IRP meeting. While the requirements do not explicitly state how the notice should be provided, ENO has consistently provided notice in two ways. First, notice is made in the print edition of the Times-Picayune and separately in the New Orleans Advocate. Second, notice is contemporaneously posted to ENO's public IRP website. Both actions are taken no later than 30 days prior to the public meeting as required by the Council. Further, ENO is aware that various stakeholders normally take separate actions to further "spread the word" in order to make the public aware that ENO is holding a meeting.

Each meeting is open to the public and does not require participants to register in advance in order to attend or even participate. By providing public notice in two major news outlets and on the public IRP website, ENO has consistently sought to encourage participation by members of the public interested in learning about the IRP process and providing input to the development of the 2015 IRP. Moreover, ENO invited any questions or concerns to be voiced during the 7-day public comment period following the technical conferences, and for those members of the public who cannot attend a meeting, all of the meeting materials are posted to the IRP website for review (www.entergy-neworleans.com/IRP/).

Regarding location of the public meeting, all of the meetings are held at the University of New Orleans' Lakefront Campus in order to provide a central, accessible, consistent and neutral meeting location. Generally speaking, attendance by the public has varied at each meeting; however, ENO does not believe that is due to the location. Conducting the meetings in locations that may be more conducive to participation by certain residents of the City may be less conducive to others. ENO believes that a balance must be struck regarding the approach to public involvement as it would be irrational and cost-prohibitive to design a process in which all of ENO's customers were able to participate in the public meetings directly.

Stakeholder Input Case

In addition to creating the four scenarios (Industrial Renaissance, Business Boom, Distributed Disruption, and Generation Shift), a Stakeholder Input Case scenario was created based on the most up to date assumptions available to ENO as of December 2015. This alternative case was conducted based on input from the Advisors and intervenors that the assumptions used in the IRP were dated and not reflective of current events. The evaluation period for the Stakeholder Input case is 2016-2035. It is important to note that the various assumption changes are detailed below; however, direct comparison of the results from the Stakeholder Input Case and the results of the four scenarios developed at the beginning of the IRP process is not appropriate.

TECHNOLOGY ASSESSMENT

The Stakeholder Input case scenario modeled four main technology types. Frame CT and Frame CCGT technology was based on the Mitsubishi Heavy Industries G Frame turbines. G Frame technologies have a lower heat rate than the F Frame technologies, as well as higher capacity. As part of the Stakeholder Input Case, the cost curve for Solar PV technology was updated based on the October 2015 IHS CERA Solar Report and is a region specific forecast (MISO South). Figures 5 and 6 below shows how Solar PV cost estimates changed over time throughout the IRP process and how IHS CERA's estimates compare to other industry standards.

Table 6: Stakeholder Input Case Technology Assumptions

Stakeholder Input Case Technology Assumptions		
Technology	**Capacity (MW)**	**Capital Cost ($/kW)[32]**
G Frame CT	250	$734
1x1 G Frame CCGT	450	$1139
Wind	Variable[33]	$2087
Solar PV (tracking)	Variable[34]	$1838

[32] 2016 Nominal Cost. Capacity rating for gas fired resources based on ICAP.
[33] Effective capacity of a wind installment is based on MISO's 15/16 capacity credit of 14.7%.
[34] Effective capacity of a solar installment is based on MISO's 15/16 capacity credit of 25%.

Figure 5: Timeline of Solar Tracking Install Costs (2013$/kW)

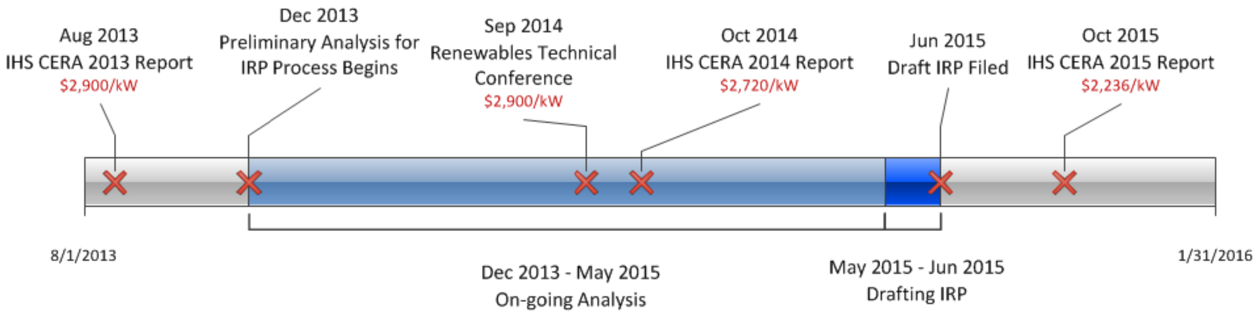
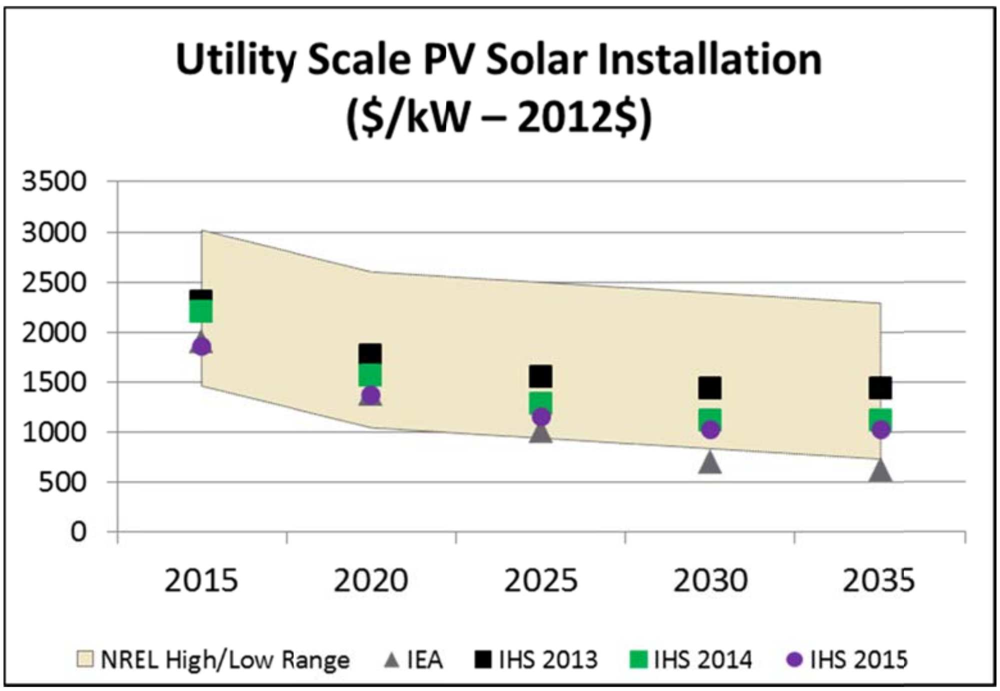


Figure 6: Solar PV Tracking Install Cost Comparison by Source



DEMAND SIDE MANAGEMENT

In an update to the draft IRP, filed on September 18, 2015, certain updates to the DSM component of the IRP were included. To reflect input from the Advisors regarding Council-approved incentives available to ENO for years 5 and 6 of Energy Smart, ENO included the assumption that the incentives would be available associated with the long-term DSM potential identified in the IRP, and were modeled as part of the total cost of the DSM programs. In addition, updated load reduction information for three demand response programs not included in the draft IRP were provided by ICF and re-evaluated for inclusion in the Final IRP. These three programs were the Dynamic Pricing Program, Non-Residential Dynamic Pricing

Program, and Direct Load Control Program. Through the updated analysis, it was determined that all three of these programs were cost-effective, and are now included in the Preferred Portfolio.

In addition to the changes made on September 18, 2015, the Stakeholder Input Case includes a secondary analysis of DSM programs that did not break even in the 20-year evaluation period. This analysis incorporated the trailing benefits (kWh savings) that a program might exhibit beyond the 20-year evaluation period. It was assumed that further investment into the DSM measures would no longer occur after 2035, thus making the cost of DSM beyond the evaluation period zero for each program. The trailing benefits declined at different rates for each program, affecting the amount of kWh savings and how long the benefits endured after 2035. These trailing benefits were included in a new breakeven analysis to determine if more DSM programs would be selected, resulting in the potential for an additional two DSM programs not previously included to become cost-beneficial when including trailing benefits. *It should be noted that projecting trailing benefits is highly uncertain and may lead to the adoption of DSM programs that do not meet near-term kWh savings goals*.

NATURAL GAS PRICE

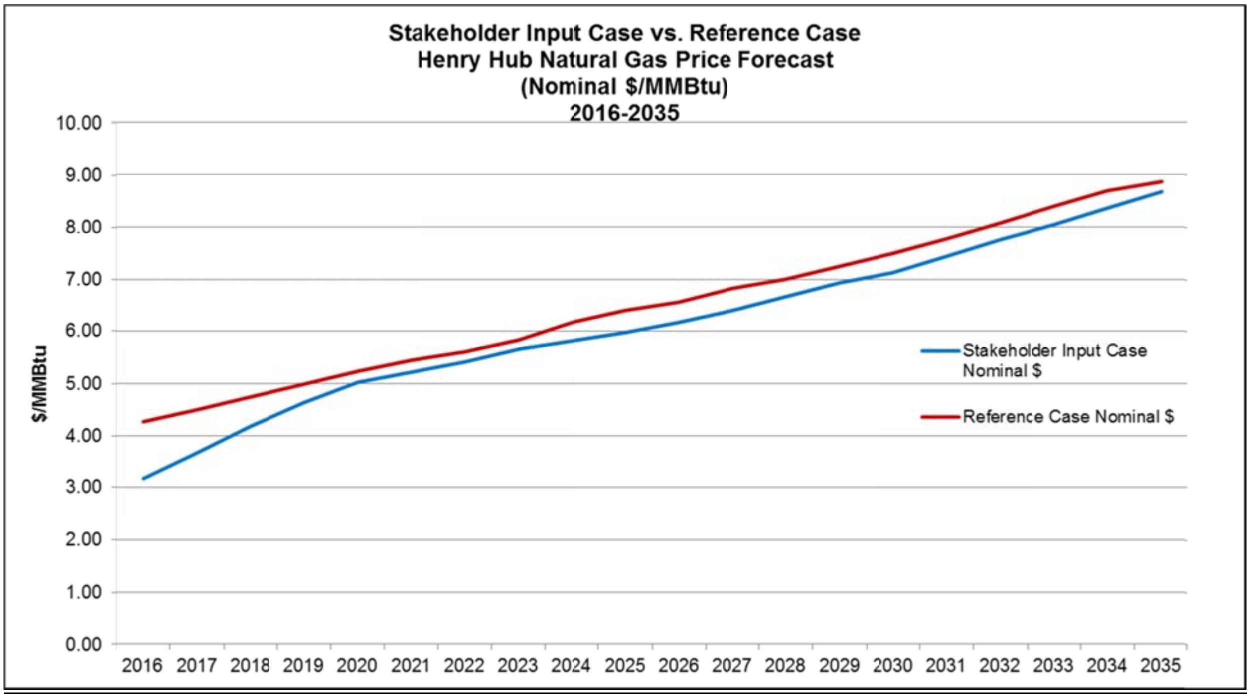
The natural gas price forecast for the Stakeholder Input Case was lower than the reference case forecast used in the Industrial Renaissance scenario. This forecast was influenced by historically strong production driven by the continued economics of Northeast shale gas combined with mild weather. These factors have created a supply and storage glut. This oversupply is expected to continue in the near-term and put downward pressure on prices, assuming normal weather patterns. Long-term structural demand increases (LNG exports, exports to Mexico, power demand) are expected to continue to develop, holding off potential price decreases in the long-run.

Table 7: Stakeholder Input Case Natural Gas Price Forecast

Henry Hub Natural Gas Prices		
	Nominal $/MMBtu	**Real 2014$/MMBtu**
Real Levelized[35] (2016-2035)	$5.54	$4.57
Average (2016-2035)	$6.12	$4.76
20-Year CAGR	5.2%	3.2%

[35] "Real levelized" prices refer to the price in 2014$ where the NPV of that price grown with inflation over the 2016-2035 period would equal the NPV of levelized nominal prices over the 2016-2035 period.

Figure 7: Stakeholder Input Case Natural Gas Price Forecast

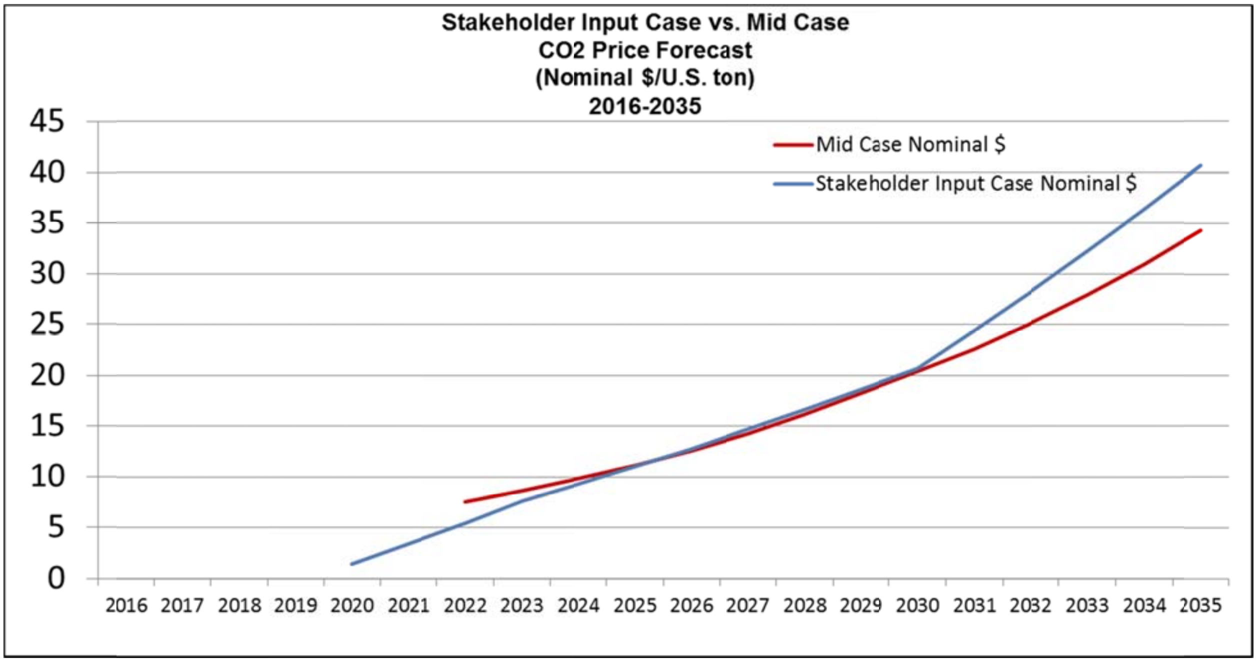


CO_2 PRICE

The Stakeholder Input Case CO_2 price forecast was taken from Entergy corporate CO_2 POV developed in March 2015. The basis for Entergy corporate POV for the mid-price forecast shown below is based on the ICF 1Q 2015 Reference Case. The Stakeholder Input Case forecast shows CO_2 prices that begin in 2020 at $1.39/U.S. ton and escalate more quickly than the mid-price forecast. The 2016-2035 levelized cost in 2014$ for the Stakeholder Input Case is $8.00/U.S. ton.[36]

[36] Includes a discount rate of 7.12%.

Figure 8: Stakeholder Input Case CO_2 Price Forecast



SECTION 3: CURRENT FLEET & PROJECTED NEEDS

Current Fleet

ENO currently controls approximately 1,318 MW of generating capacity either through direct ownership or through life-of-unit contracts with affiliate EOCs. Table 6 indicates the supply resources by fuel type measured in installed MW with percentages of the overall portfolio.

As reflected in Table 8, over half of ENO's existing generating capacity consists of legacy gas units — Michoud Units 2 and 3; however, they only contribute approximately 18% of ENO's energy requirements. Both units are currently scheduled to deactivate June 1, 2016, which creates room in the portfolio for modern gas-fired peaking resources.

Upon close of the acquisition by ENO of Power Block 1 of the Union Power Station, ENO will add approximately 510 MW of modern and highly efficient CCGT capacity to its portfolio helping to fill a significant portion of the long-term need caused by the deactivation of Michoud Units 2 and 3. When combined with ENO's existing baseload resources, the addition of Union to ENO's portfolio is expected to substantially meet ENO's long-term baseload and load-following resource needs. ENO's remaining needs will necessitate replacement resources that are designed to provide low cost capacity and produce limited amounts of energy. Peaking resources such as Combustion Turbines ("CT") are particularly well suited to meet this need. ENO's existing portfolio does not currently include a CT resource.

Table 8: ENO's Current Resource Portfolio

Resource Type	MW	%
Coal	32	2.4
Combined Cycle Gas Turbine (CCGT)	112	8.5
Nuclear	392	29.7
Legacy Gas	782	59.3
Total	1318	100.0

Historical production costs for ENO's current fleet can be seen in Table 9 below.

Table 9: ENO Historical Production Costs of Current Fleet

ENO Production Costs			
	Year-end		
	2012	**2013**	**2014**
MWhs (net Non-Requirements Sales for Resale and Net Transmission Losses)	5,192,000	5,370,000	5,314,000
Total Production Cost ($)	$302,950,000	$348,920,000	$324,883,000
Total Production Cost ($/MWh)	$58.35	$64.98	$61.14
RPCE equalization receipts/(payments)	$14,599,000	$15,325,000	-
Total Production Cost with RPCE receipts/(payments) ($)	$288,351,000	$333,595,000	$324,883,000
Total Production Cost with RPCE receipts/(payments) ($/MWh)	$55.54	$62.12	$61.14

DEACTIVATION OF MICHOUD 2 AND 3

ENO's existing Michoud Units 2 and 3 are scheduled to deactivate June 1, 2016. Originally placed in service in 1963 and 1967, respectively, units 2 and 3 are among the oldest active Entergy-owned units in Louisiana, and significantly older than the average age of the fleet. Both units were designed to operate in load-following and baseload roles; however, both units are increasingly being dispatched with greater frequency (*i.e.,* in a peaking role) which increases operating cost and reliability fatigue associated with more start up and shut down cycles. As part of its ongoing assessment of both units, prior independent engineering studies identified the need for significant upgrades to allow for safe and reliable operations over the next 10 years. An economic analysis comparing the cost of extending the life of Michoud 2 and 3 to deactivating each unit and deploying new resources concluded that deactivation was the preferred solution in order to mitigate risks associated with uncertainty that extending the life of either unit would yield benefits to customers. Given these realities, ENO submitted an Attachment Y request to MISO to study the impact on the transmission system associated with deactivation of units 2 and 3, which study was ultimately completed approving the deactivation of both units upon completion of certain transmission upgrades.[37]

Load Forecast

A wide range of factors likely will affect ENO's electric load over the long-term, including:

- Levels of economic activity and growth;
- The potential for technological change to affect the efficiency of electric consumption;
- Potential changes in the purposes for which customers use electricity (*e.g.*, the adoption of electric vehicles);
- The potential expansion of customer-owned (*i.e.*, behind-the-meter) self-generation technologies and the long-term performance of existing installed systems (*e.g.*, rooftop solar panels); and
- The cost-effectiveness of energy efficiency, conservation measures, and demand response.

Such factors may affect both the level and shape of ENO's future loads. Peak loads may be higher or lower than projected levels. Similarly, industrial customer load factors may be higher or lower than currently projected. Uncertainties in load may affect both the amount and type of resources required to cost-effectively meet future customer needs.

In order to consider the potential implications of load uncertainties on long-term resource needs, four load forecast scenarios were prepared for the 2015 IRP, which are described in general below:

[37] For additional details regarding the condition assessment of Michoud Units 2 and 3, see Technical Supplement 7].

INDUSTRIAL RENAISSANCE – REFERENCE LOAD

Assumes significant load growth will occur in the commercial class due to known commercial projects. Distributed generation in the form of rooftop solar is expected to dampen growth in the residential and commercial classes.

BUSINESS BOOM

Assumes smaller impact from distributed generation, accelerated ramp of a commercial project, and a load expansion at a commercial project.

DISTRIBUTED DISRUPTION

Decrements the Reference load scenario for Combined Heat and Power ("CHP") impact and distributed solar PV system impact.

GENERATION SHIFT

Assumes distributed generation will have a greater impact on residential and commercial growth. Also assumes major new commercial project is delayed.

METHODOLOGY

SPO has consistently used Itron computer software to develop the IRP load forecasts. Itron is used to develop a 20-year, hour-by-hour load forecast. The MetrixND®[38] and the MetrixLT™[39] programs are used widely in the utility industry, to the point where they may be considered an industry standard for energy forecasting, weather normalization, and hourly load and peak load forecasting.

To develop the load forecast, SPO allocates ENO's Retail Energy Forecast (by month) and the Wholesale Energy Forecast (by month) to each hour of a 20-year period based on historical load shapes developed by ESI's Load Research Department. Fifteen-year "typical weather" is used to convert historic load shapes into "typical load shapes." For example, if the actual sales for the Company's residential customers occurred during very hot weather conditions, the typical load shape would flatten the historic load shape. If the actual weather were mild, the typical load shape would raise the historic load shape. Each customer class responds differently to weather, so each has its own weather response function. MetrixND® is used to adjust the historical load shapes by typical weather, and MetrixLT™ is used to create the 20-year, hourly load forecast.

[38] MetrixND by ITron is an advanced statistics program for analysis and forecasting of time series data.
[39] MetrixLT™ by ITron is a specialized tool for developing medium and long run load shapes that are consistent with monthly sales and peak forecasts.

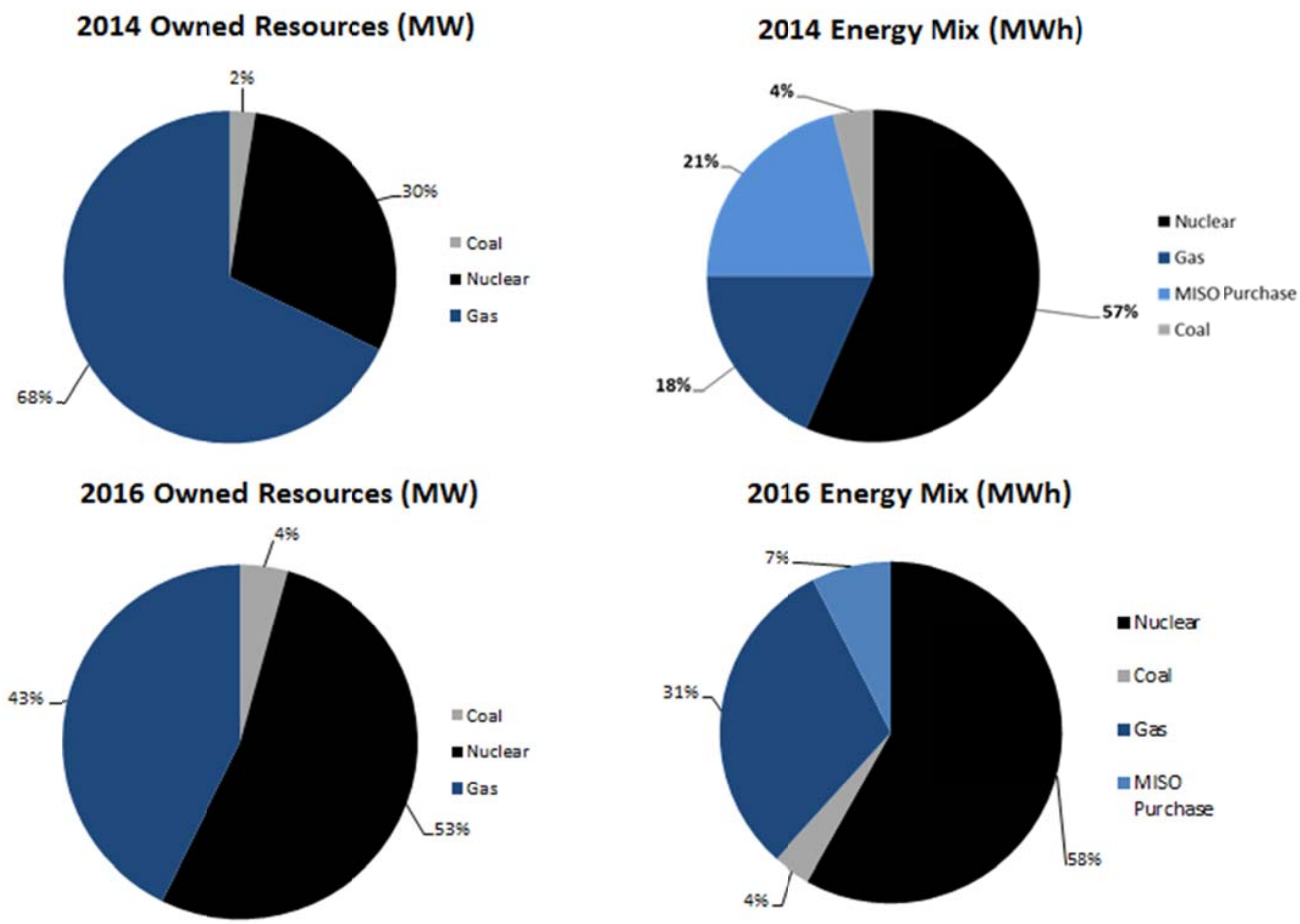
The load forecast is then grossed up to include average transmission and distribution line losses. Loss factors are applied to each revenue class after the forecast is developed and after accounting for energy efficiency.

Energy savings from company-sponsored DSM programs are decremented from the Retail energy forecast. Energy savings from naturally occurring energy efficiency, as estimated by the Energy Information Administration, are also taken into consideration. The load forecast uses the decremented energy forecast to develop annual peaks that reflect the savings from utility-sponsored programs as well as non-utility sponsored customer adoption of more efficient technologies.

Resource Needs

Over the 20-year planning horizon of the IRP, ENO expects to add new generating capacity, as the DSM Potential Study did not identify enough cost-effective achievable DSM resources to independently meet ENO's projected needs. ENO's long-term resource needs are driven primarily by the scheduled deactivation of the approximately 781 MW Michoud Units 2 and 3 in 2016. Michoud Units 2 and 3 are scheduled to deactivate due to high expected forward costs to sustain these older units. These units represent over half of ENO's existing capacity, but do not provide an equivalent amount of energy. Following the planned deactivation of Michoud 2 and 3, ENO's nuclear (and to a lesser extent, coal) resources will provide about 57% of ENO's capacity and over 60% of energy as shown in Figure 9 below. Although the deactivation of Michoud Units 2 and 3 will result in a significant need for replacement capacity resources, those resources would not be called on to generate an equivalent amount of energy. Following the planned deactivation of Michoud Units 2 and 3, the fuel mix of ENO's energy resources will remained balanced with a significant portion sourcing from stable-priced base load nuclear resources, leaving room for cost-effective gas-fired resource additions beyond ENO's share of the new Ninemile 6 CCGT resource and Power Block 1 of the Union Power Station.

Figure 9: ENO's Capacity and Energy Mix



Based on current deactivation assumptions, no other units are expected to deactivate during the planning period. Assumptions made for the IRP are not final decisions regarding future investment in any identified or planned resource. Unit-specific portfolio decisions, such as sustainability investments in legacy resources, environmental compliance investments, or unit deactivations, are based on economic and technical evaluations considering such factors as projected forward costs, anticipated operating roles, and the cost of supply alternatives at the time of the decision. These factors are dynamic, and as a result, actual decisions may differ from planning assumptions as greater certainty is gained regarding requirements of legislation, regulation, and relative economics.

As shown in Table 10, by 2034, it is expected that ENO will experience between 123 MW and 160 MW of total load growth.

Table 10: Projected Peak Forecast Increase from 2015

	Industrial Renaissance (MW)	Business Boom (MW)	Distributed Disruption (MW)	Generation Shift (MW)
By 2034	147	160	123	146

The combination of the projected load growth and the planned deactivation of the Michoud units will result in a significant need for long-term capacity resources as shown in Table 11. By 2034, ENO's projected capacity need (before planned additions) is expected to be approximately 781 MW.

Table 11: ENO Resource Needs by Scenario (MW)

Capacity Surplus/(Need) (Before IRP Additions)				
	Industrial Renaissance	**Business Boom**	**Distributed Disruption**	**Generation Shift**
By 2024	(691)	(727)	(683)	(688)
By 2034	(781)	(821)	(753)	(778)

**Includes 12% planning reserve margin*

ENO has a number of alternatives for meeting its long-term resource needs, including:

- Incremental long-term resource additions including:
    - Self-Supply alternatives
    - Acquisitions
    - Long Term PPAs
- Demand Side Resources
    - Energy efficiency
    - Demand response

As a member of MISO, ENO has access to a large structured marketplace that offers short-term capacity and energy products. While those alternatives are viable alternatives for meeting ENO's short-term resource needs, they are not appropriate for meeting long-term resource needs.

Types of Resources Needed

In order to provide safe and reliable service to its customers at the lowest reasonable cost, ENO must maintain a portfolio of generation resources that includes the right amount and types of capacity. With respect to the amount of capacity, ENO must maintain sufficient generating capacity to meet its peak load plus a planning reserve margin. As described above, ENO plans to meet its annual reserve margin target, which is assumed to be 12% for long-term planning. In general, as demonstrated in Table 12, ENO's capacity needs by supply role include:

- Base Load – expected to operate in most hours.
- Load-Following – capable of responding to the time-varying needs of customers.
- Peaking and Reserve – expected to operate relatively few hours, if at all.

Table 12: Projected Resource Needs in 2034 by Supply Roles (without Planned Additions) in Industrial Renaissance Scenario

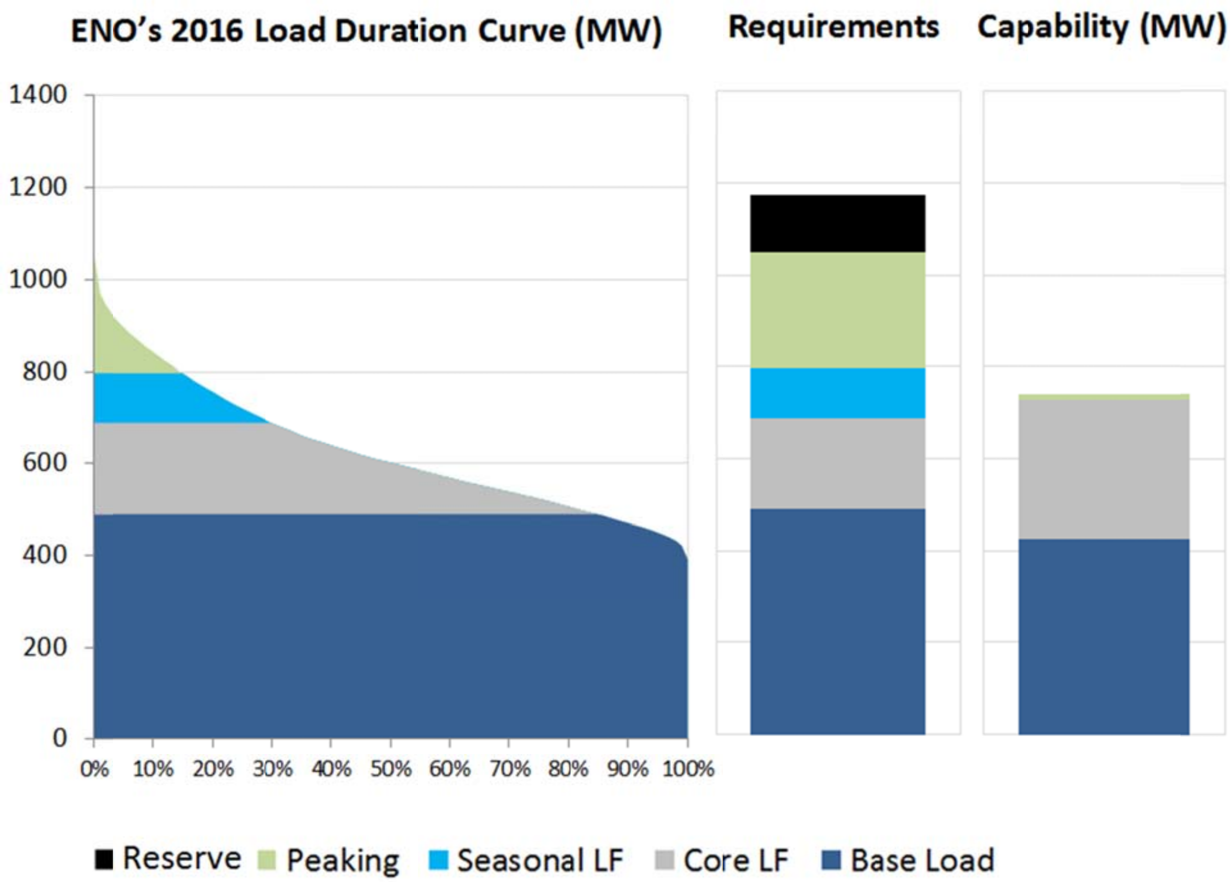
	Need	Resources	Surplus/ (Deficit)
Base Load and Load-Following (MW)	915	525	(390)
Peaking & Reserve (MW)	403	12	(391)
Totals	1318	537	(781)

However, with the planned addition of the Council approved Union resource, ENO would expect to meet its base load and load-following resource needs as indicated in Table 13.

Table 13: Projected Resource Needs in 2034 by Supply Roles (with Planned Additions) in the Industrial Renaissance Scenario

	Need	Resources	Surplus/ (Deficit)
Base Load and Load Following (MW)	915	965	50
Peaking & Reserve (MW)	403	12	(391)
Totals	1318	977	(781)

Figure 10: ENO's Supply Role Needs 2016



Following the deactivation of Michoud Units 2 and 3 and the close of the transaction to acquire the Union Power Block 1 resource, both in 2016, ENO's remaining need is primarily for peaking and reserve resources. Peaking requirements are most economically served with resources with low fixed costs and quick start times. Peaking units, such as CTs, typically operate at a capacity factor of less than 15% and are particularly well suited to meet this need. Thus, the evaluation of adding CT resources to ENO's portfolio for further evaluation is a prudent and reasonable step that was evaluated further in the detailed stages of the modeling for the 2015 IRP, and is discussed further below. As indicated by the DSM Potential Study, there are not enough cost-effective demand-side resources to meet ENO's projected peaking resource needs. In addition, because 1 MW of renewable resources such as wind and solar only provide approximately .14 - .25 MW of capacity toward meeting ENO's resource needs, ENO demonstrates in Section 4 and 5 below that renewables such as wind and solar cannot be relied upon to cost-effectively meet ENO's projected resource needs following the planned deactivation of Michoud Units 2 and 3.

Current Fleet & Projected Needs: Stakeholder Input Case

Due to the changes that were filed September 18, 2015 and the creation of the Stakeholder Input Case, the differences in the current fleet assessment and projected needs assessment are documented below.

FINAL IRP UPDATE ON CURRENT FLEET

ENO received Council approval for the transfer of Algiers from ELL to ENO in May 2015, which transaction closed on September 1, 2015. The Algiers resources were included in the portfolio of the existing fleet of the Stakeholder Input Case, resulting in an increase of 117 MW from 537 MW to 654 MW of owned resources and affiliate power purchase agreements in 2016.

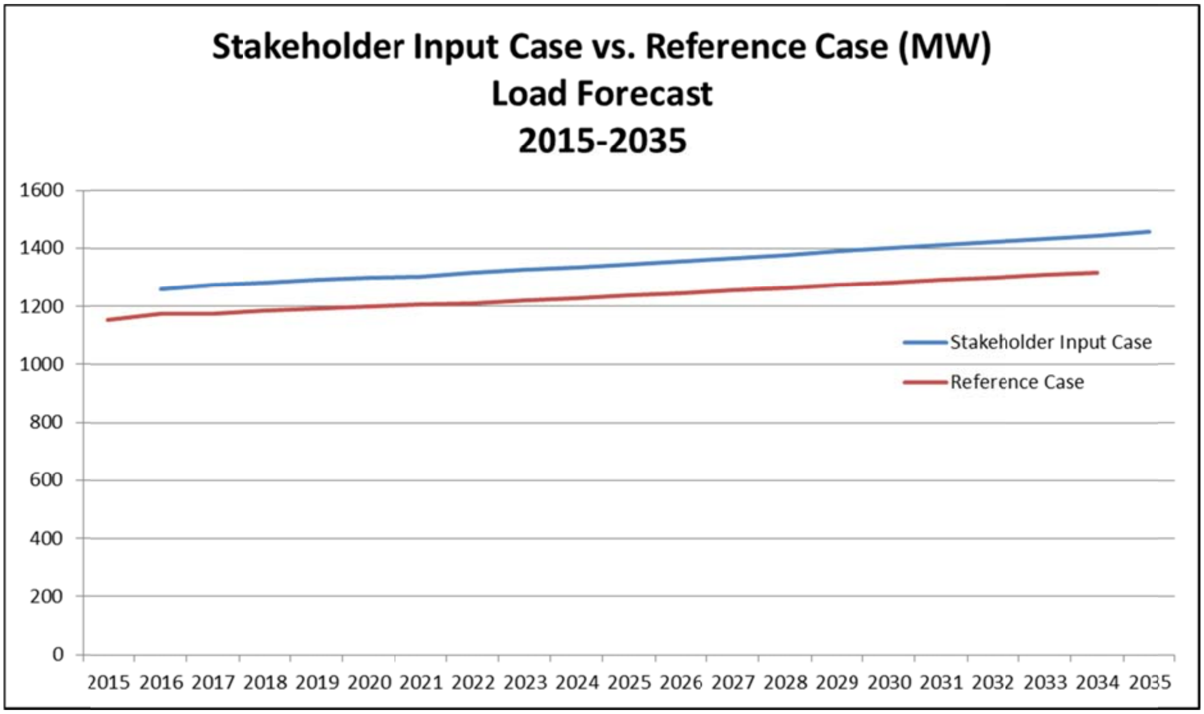
Table 14: Incremental Capacity from Algiers Transfer (MW)

Resource Name	Resource Type	MW
Acadia	CCGT	7
Buras 8	Legacy Gas	0.2
Grand Gulf	Nuclear	3
Little Gypsy 2	Legacy Gas	8
Little Gypsy 3	Legacy Gas	10
Ninemile 4	Legacy Gas	13
Ninemile 5	Legacy Gas	13
Perryville 1	CCGT	2
Perryville 2	CT	1
Riverbend	Nuclear	4
Waterford 1	Legacy Gas	7
Waterford 2	Legacy Gas	8
Waterford 3	Nuclear	21
Waterford 4	Oil	1
Sterlington 7	CCGT	1
Ninemile 6	CCGT	6
Oxy-Taft	CCGT	9
Toledo Bend	Hydro	0.4
Vidalia	Hydro	2
Total		117

LOAD FORECAST

For the Stakeholder Input Case, the load was changed to reflect the load forecast of the most current business plan, which also included the Algiers transfer. This resulted in an increase of 84 MW in the total resource requirement in 2016 compared to the Final IRP reference case load.

Figure 11: Stakeholder Input Case Load Forecast



RESOURCE NEEDS

Resource needs changed in the Stakeholder Input Case due to changes in the load forecast as well as the addition of incremental capacity from the Algiers transfer. Planned resource additions also changed from the affiliate PPA's of the Union and Amite South resources to the ownership of Union Power Block 1. This change is highlighted in Table 15 below. Despite these changes to the Stakeholder Input Case, ENO's needs were determined to be similar to the reference case: ENO largely meets its base load/core load-following need while still being deficient in peaking and total capacity.

Table 15: Reallocation of Planned Resource Additions

Reallocation of Planned Resource Additions			
Resource	**IR/BB/DD/GS Scenarios (MW)**	**Stakeholder Input Case (MW)**	**Change**
Union	204	510	306
Amite South	229	0	(229)
Totals	433	510	77

Table 16: Stakeholder Input Case Projected Peak Forecast Increase by 2035

Stakeholder Input Case (MW)		
2016	**2035**	**Increase**
1,125	1,301	176

Table 17: Stakeholder Input Case ENO Resource Needs (MW)

Capacity Surplus/(Need) (Before IRP Additions)	
By 2025	(685)
By 2035	(901)

Table 18: Projected Resource Needs in 2035 by Supply Roles (Stakeholder Input Case)

	Need	Resources	Surplus/ (Deficit)	Planned Additions	Surplus/ (Deficit)
Base Load and Load-Following (MW)	1043	526	(517)	510	(7)
Peaking & Reserve (MW)	414	30	(384)	0	(384)
Totals	1457	556	(901)	510	(391)

SECTION 4: PORTFOLIO DESIGN ANALYTICS

The IRP utilized a two-step approach to construct and assess alternative resource portfolios to meet the customer needs:

1. Market Modeling
2. Portfolio Design & Risk Assessment

Market Modeling

The first step of the IRP modeling process was to develop within the AURORA model a projection of the future power market for each of the four scenarios. This projection looks at the power market for the entire MISO footprint excluding New Orleans to gain perspective on the broader market outside the state. The purpose of this step was to provide projected power prices to assess potential portfolio strategies within each scenario as resource additions made outside of New Orleans will have an impact on the economics of the resource alternatives available to ENO. In order to achieve this, assumptions were required about the future supply of power. The process for developing those assumptions relied on the AURORA Capacity Expansion Model to identify the optimal set of resource additions in the market to meet reliability and economic constraints. Resulting assumptions regarding new capacity additions in each scenario are summarized in Table 19. It is important to recognize that the resource additions identified in Table 19 are what the AURORA model predict would be added outside of New Orleans by other companies to meet the capacity and energy requirements of the MISO market excluding New Orleans. In this way, ENO is attempting to model and isolate the effect of resource additions outside of New Orleans in order to establish a benchmark for evaluation of the optimal combination of resource additions in New Orleans.

Table 19: Results of MISO Market Modeling

Results of MISO Market Modeling (MISO Footprint, excluding New Orleans) Incremental Capacity Mix by Scenario				
	Industrial Renaissance (Ref. Case)	**Business Boom**	**Distributed Disruption**	**Generation Shift**
CCGT	45%	81%	97%	61%
CT	55%	19%	3%	3%
Wind	0%	0%	0%	12%
Solar	0%	0%	0%	24%
Year of First Addition	2017	2017	2017	2017
Total GWs Added (through 2034)	59	65	39	101

The results of the Capacity Expansion Modeling are supported by conclusions from the Technology Assessment, as discussed earlier, were reasonably consistent across scenarios. These results, as summarized below, are the output of the model based on the market conditions that the model analyzed:

- In general, new build capacity is required to meet overall reliability needs.
- Gas-fired resources, CTs and CCGTs, are the preferred technologies for new build resources in most outcomes.
- The model did not select new nuclear or new coal for any scenario.
- Solar PV and wind generation has a significant role in only one of the scenarios, which assumes high gas and carbon prices and the continuation of subsidies.

Portfolio Design & Risk Assessment

The IRP informs future planning and procurement activities. In order to establish a potential resource mix for a given scenario, ENO first relied on the AURORA Capacity Expansion Model to develop the optimal DSM program mix. After assessing DSM programs, ENO relied on AURORA to create an optimal portfolio, with both demand- and supply-side resources, for each scenario. Based on these results, ENO designed additional portfolios based on ENO's planning objectives and needs.

The AURORA Capacity Expansion Model analyzes least cost portfolios to meet ENO's resource needs using the cost-effective achievable demand-side resources identified in the ICF DSM Potential Study, and the supply-side resource alternatives identified in the Technology Assessment. The AURORA Capacity Model was used to develop a portfolio for each of the scenarios in a two-step process, which first assessed DSM programs, and then supply-side alternatives. DSM programs were evaluated first without consideration of supply-side alternatives by allowing the AURORA Capacity Expansion Model to determine which of the DSM programs may be able to provide capacity and energy benefits in excess of their costs. All economic DSM programs were included in each portfolio.[40] The specific programs selected for each scenario are listed in Appendix A to this report. In addition to this analysis, in response to

[40] In evaluating the economics of DSM programs, the model evaluates the cost and benefit of the DSM programs, but does not take into consideration ratemaking and policy issues implicated by DSM programs, which must be appropriately addressed as part of DSM implementation.

comments received following Milestone 2 of the IRP process, ENO conducted additional sensitivity analysis of the reference case DSM Portfolio to ensure that the cost-effectiveness of the selected programs, as well as those that were not selected, would not be significantly affected by either having to compete with supply-side resource alternatives or delaying their implementation start date beyond 2015. In both cases, the analysis supports the selected programs as a reasonable basis for determining which programs to include in the Preferred Portfolio. [41]

Once the level of economic DSM was determined within each scenario/portfolio combination, the AURORA Capacity Expansion Model was used to identify the most economic level and type of supply-side resources needed to meet reliability requirements. The result of this process was a portfolio of both DSM and supply-side alternatives that produces the lowest total supply cost to meet the identified need in each scenario. Table 20 details the resource mix for the AURORA Capacity Expansion Portfolios.

Table 20: AURORA Capacity Expansion Portfolio Design Mix

AURORA Capacity Expansion Portfolio Design Mix				
	Industrial Renaissance (Ref. Case)	Business Boom	Distributed Disruption	Generation Shift
DSM	14 Programs	12 Programs	15 Programs	17 Programs
DSM Maximum (MW)[42]	41	26	40	43
CCGTs (MW)	382	382	382	0
CTs (MW)	0	0	0	0
Solar (MW)	0	0	0	1,150
Wind (MW)	0	0	0	50

As demonstrated in the Section 3 above, ENO's projected supply role needs are primarily for peaking and reserve resources. The results of the AURORA Capacity Expansion Portfolios selected mainly base load and load-following resources. This is due in large part to the way in which AURORA evaluates the resources alternatives. In AURORA, a resource is dispatched based on its ability to serve the load in MISO, regardless of who owns the generating resources. Because CCGT resources are expected to be dispatched before peaking resources due to their

[41] This analysis was shared publicly at the Interim Milestone public meeting held on May 27, 2015, and is available on ENO's IRP website located at www.entergy-neworleans.com/IRP/.

[42] Demand Side Management (DSM) total is grossed up for Planning Reserve Margin (12%) and transmission losses (2.4%).

relative efficiency, the selection by AURORA of CCGT resources to serve load in MISO is predicated on the need for the energy those resources are dispatched to serve. ENO's challenge is that while CCGT resources may be more economic than peaking resources (*e.g.*, CTs), it would not be prudent for ENO to add CCGT resources to its capacity portfolio if it does not have a corresponding need for the energy those resources are expected to produce when dispatched by MISO. If ENO were to add more CCGT resources beyond Union Power Block 1 than can be supported by the supply role needs analysis discussed in Section 3, effectively ENO would be exposing its customers to unnecessary risk associated with the known high fixed cost of CCGT resources as compared to the unknown market price for the excess energy necessary to make those resource additions economic.

As a result of this unique planning conundrum, ENO designed an additional four portfolios to reflect this challenge and develop a reasonable prudent set of alternative portfolios capable of meeting ENO's planning objectives based on the identified resource needs and the best available resource alternatives. This also provided a meaningful set of alternatives against which the AURORA portfolios could be compared. All portfolios constructed included CTs as they are well suited to economically serve ENO's peaking and reserve supply role needs. Three of the portfolios included renewable resources to assess whether a certain amount of renewable resource additions to ENO's portfolio could improve the portfolio performance in terms of cost and risk. All four of these additional portfolios relied on the Industrial Renaissance Scenario's DSM portfolio, which as discussed above proved to be robust under a range of alternative assumptions regarding start date for implementation and cost-effectiveness as compared to supply-side resource alternatives. The resulting four portfolios are described below. As discussed in more detail below, the AURORA portfolios result in the addition of resources that produce significantly more energy than identified as necessary in the analysis of ENO's resource needs by supply role, suggesting that the alternative portfolios summarized in Table 21 provide a reasonable set of alternatives prudent for further consideration in the development of the Preferred Portfolio. Figures 12 through 17 show the load and capability charts for each of the six portfolios.

Table 21: Alternative Portfolio Design Mix – Installed Capacity

Alternative Portfolio Design Mix – Installed Capacity				
	CT Portfolio	**CT/Solar Portfolio**	**CT/Wind Portfolio**	**CT/Wind/Solar Portfolio**
DSM Programs	14 Programs	14 Programs	14 Programs	14 Programs

CCGTs	0	0	0	0
CTs	194	194	194	194
Solar	0	100	0	50
Wind	0	0	100	50

Figure 12: AURORA - CCGT Portfolio

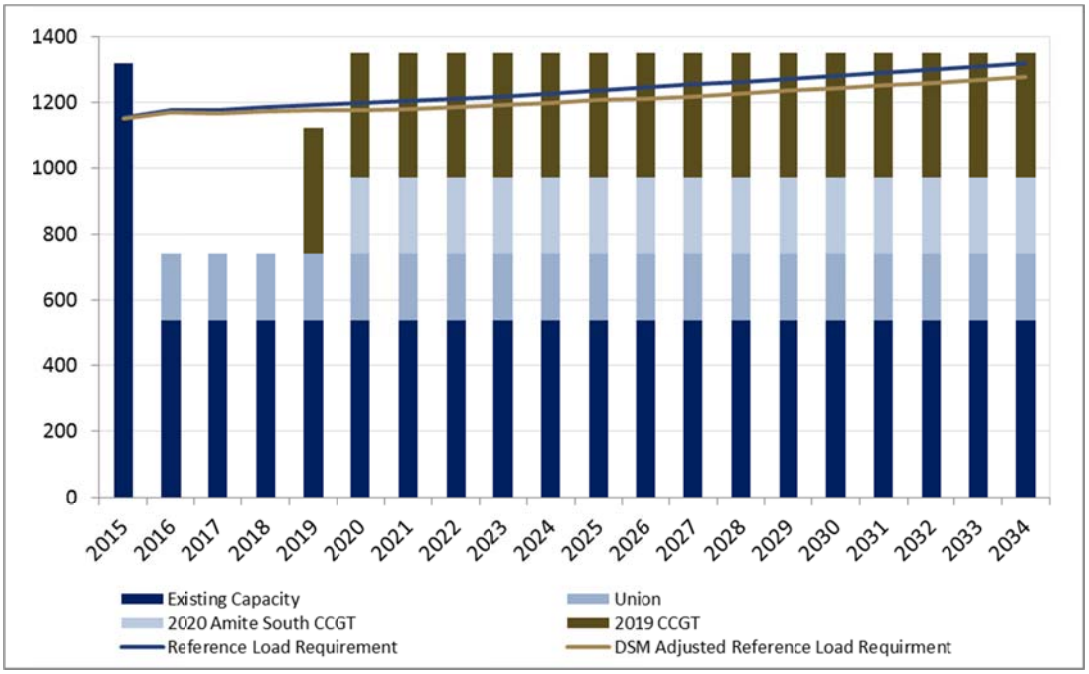


Figure 13: AURORA - Solar Portfolio

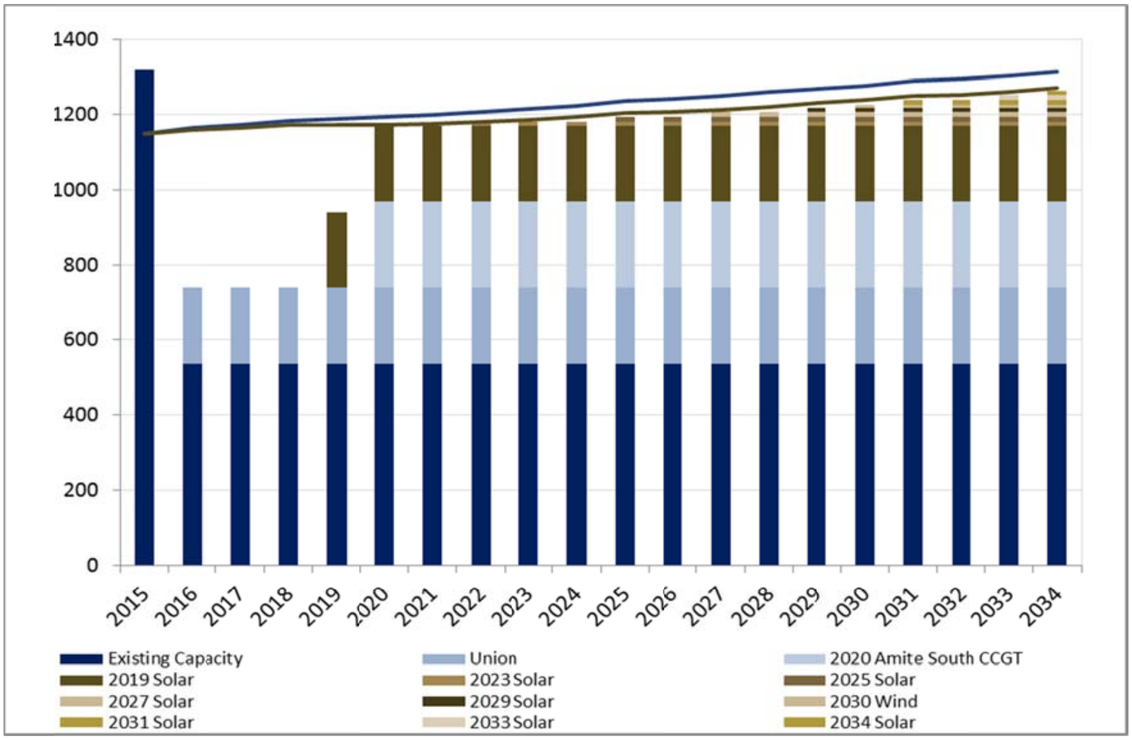


Figure 14: CT Portfolio

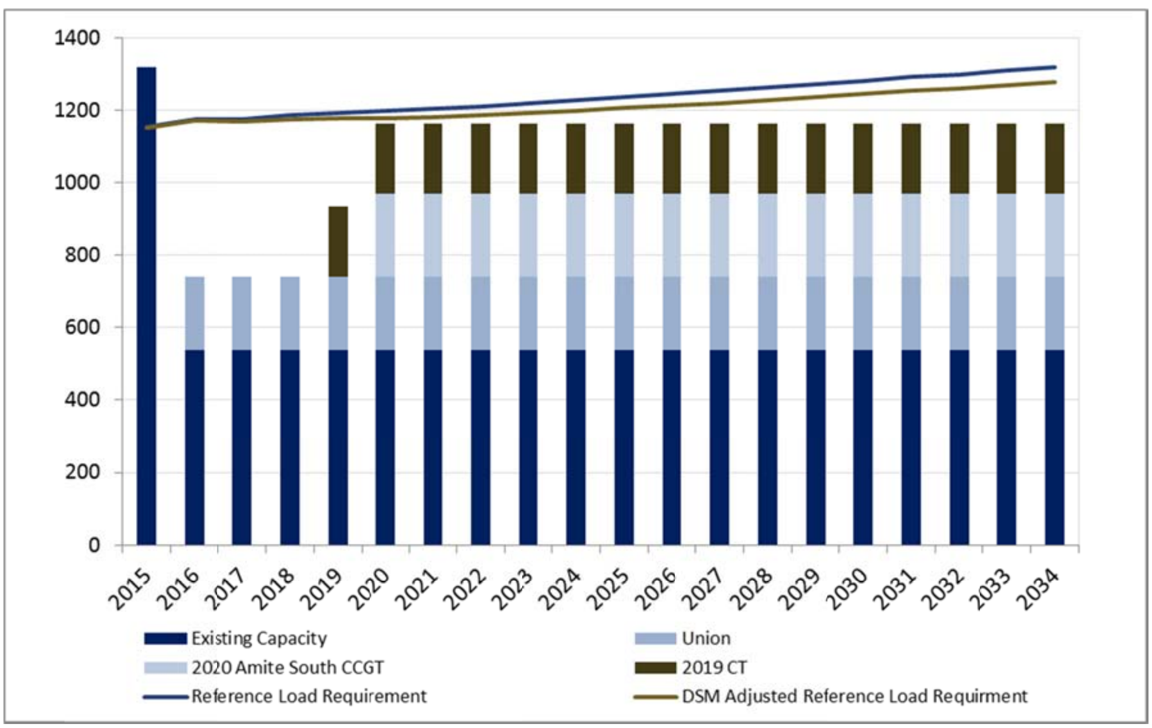


Figure 15: CT/Solar Portfolio

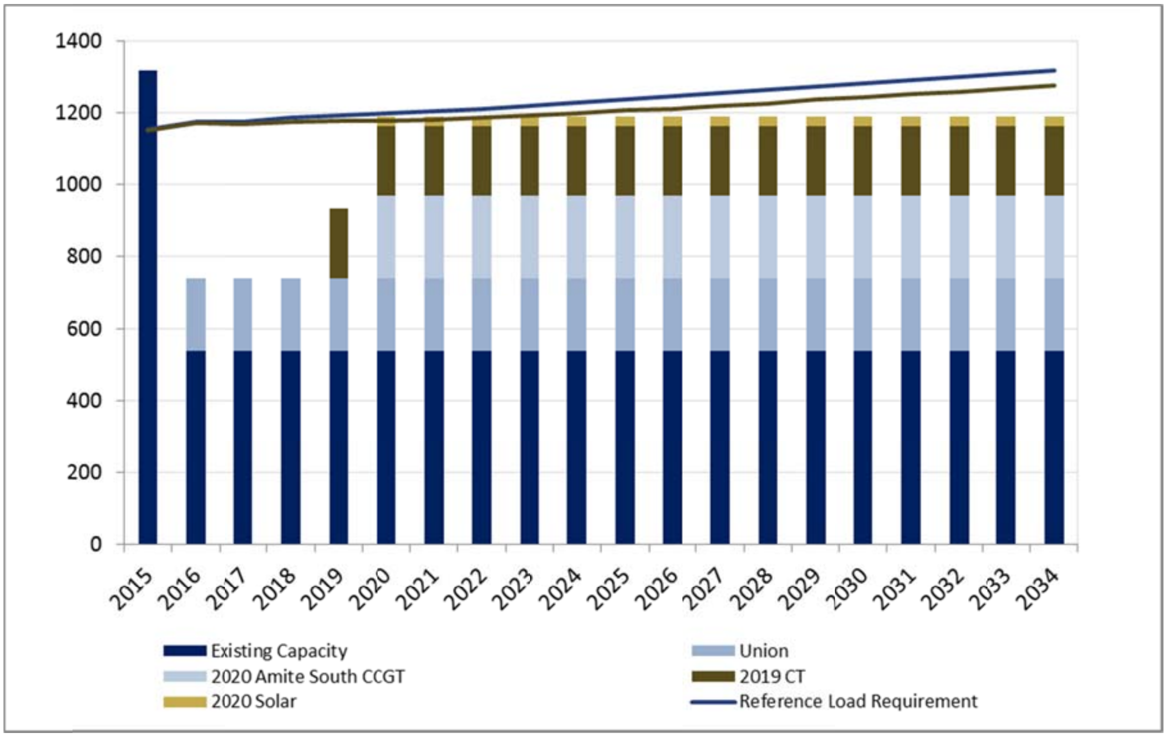


Figure 16: CT/Wind Portfolio

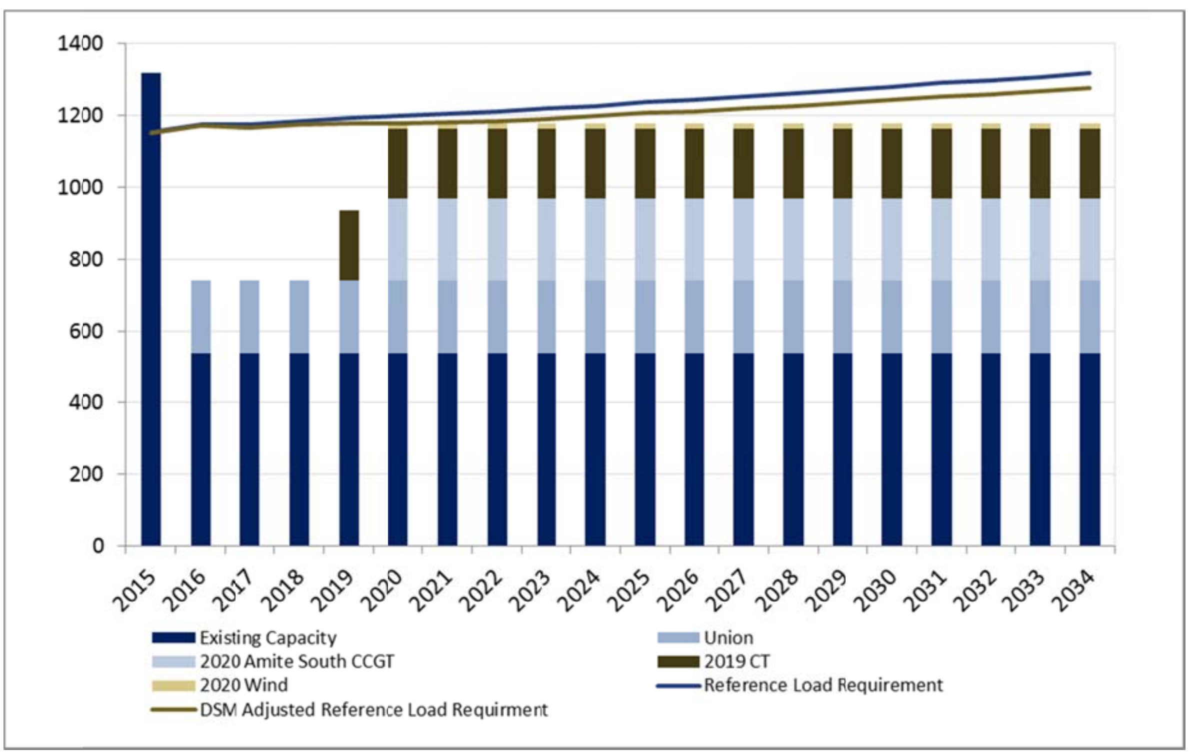
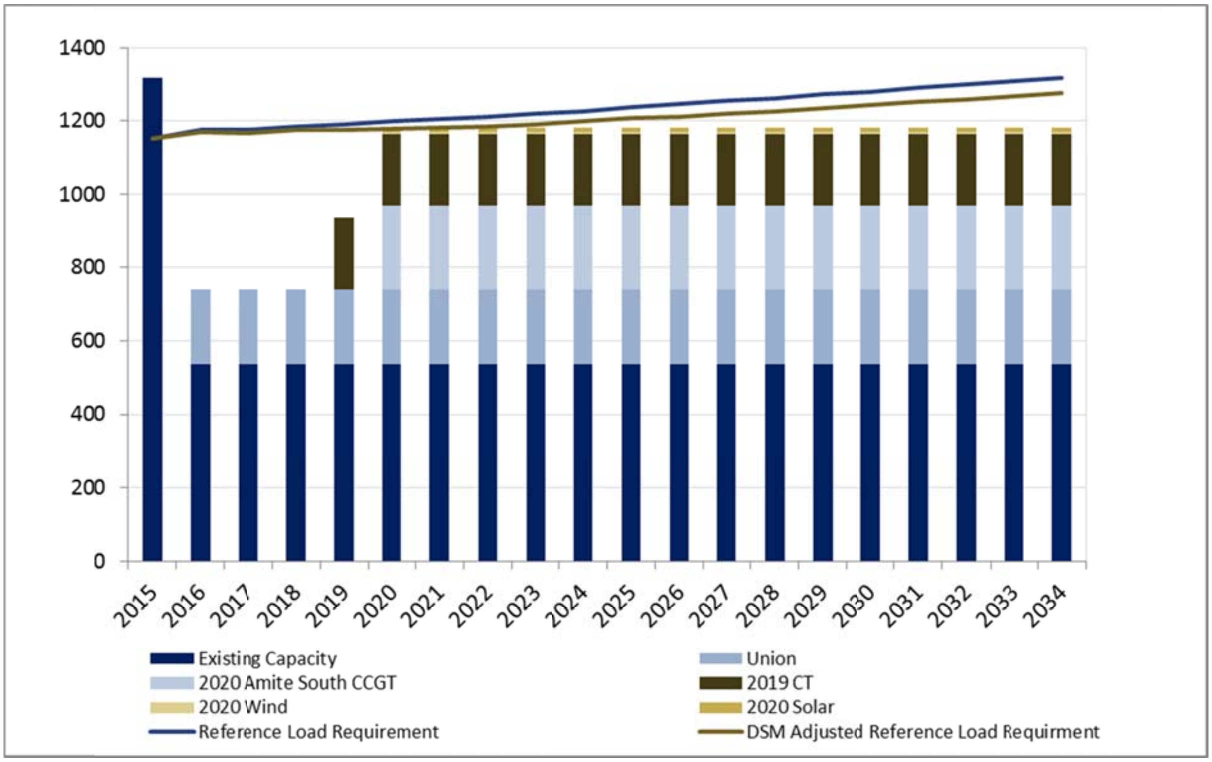


Figure 17: CT/Wind/Solar Portfolio



Each of the six portfolios illustrated above were modeled in AURORA and tested in the four scenarios described earlier to create a total of 32 cases. The results of the AURORA production cost simulations were combined with the fixed costs of the incremental resource additions to yield the total forward revenue requirements excluding sunk costs of ENO's existing portfolio. The total forward non-sunk revenue requirement results and rankings by scenario are provided in Table 22 and Table 23 below.

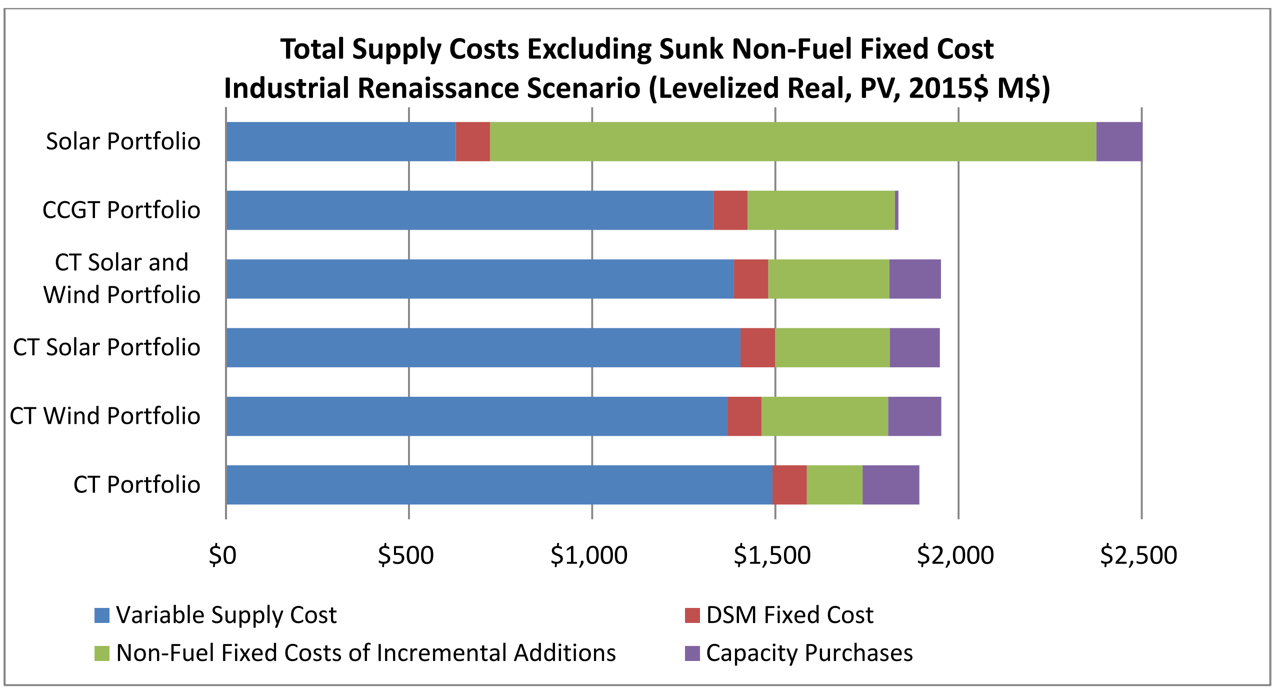
Table 22: PV of Total Supply Costs excluding Sunk Non-Fuel Costs by Scenario

PV of Forward Revenue Requirements ($M) (2015-2034)				
	IR Scenario	BB Scenario	DD Scenario	GS Scenario
AURORA - CCGT Portfolio	$1,836	$1,538	$1,754	$2,228
AURORA - Solar Portfolio	$2,501	$2,432	$2,403	$2,100
CT Portfolio	$1,893	$1,687	$1,837	$2,374

CT/Solar Portfolio	$1,949	$1,756	$1,889	$2,343
CT/Wind Portfolio	$1,952	$1,765	$1,885	$2,310
CT/Solar/Wind Portfolio	$1,951	$1,760	$1,887	$2,326

Figure 18 below, breaks down the analysis of total supply cost excluding sunk non-fuel fixed cost for each of the six portfolios using assumptions in the Industrial Renaissance Scenario into the component costs. As demonstrated in Figure 18, while the Solar Portfolio has the lowest variable supply costs, it is has the highest non-fuel fixed costs as compared to the other portfolios. In contrast, the CT Portfolio has lower non-fuel fixed costs than the other five portfolios. Because ENO's projected resource needs following the planned deactivation of Michoud Units 2 and 3 reflect the need for peaking and reserve capacity resources, more weight should be placed on the non-fuel fixed costs than variable cost savings in considering resource additions to the Preferred Portfolio.

Figure 18: Total Supply Costs Excluding Sunk Non-Fuel Fixed Costs in the IR Scenario



The columns in Table 23, below, provides the rankings of each of the six modeled portfolios in each of the scenarios based on the economic performance of the portfolios shown in Table 22.

Table 23: Portfolio Ranking by Scenario

Portfolio Ranking by Scenario				
	IR Scenario	BB Scenario	DD Scenario	GS Scenario
AURORA – CCGT Portfolio	1	1	1	2
AURORA – Solar Portfolio	6	6	6	1
CT Portfolio	2	2	2	6
CT/Solar Portfolio	3	3	5	5
CT/Wind Portfolio	5	5	3	3
CT/Solar/Wind Portfolio	4	4	4	4

Table 23 demonstrates that the CCGT Portfolio ranks higher on a total cost basis in the Industrial Renaissance, Business Boom, and Distributed Disruption Scenarios. However, the CCGT has more risk than the CT portfolios because of higher fixed costs being offset by uncertain potential variable cost savings. The Solar Portfolio ranks lowest in all of the other scenarios. Moreover, the Solar Portfolio is highly ranked in the Generation Shift Scenario due to the confluence of the assumption that the ITC and PTC subsidies will continue, gas prices will move significantly higher, and CO_2 will become regulated and at be priced at the upper bound of the IRP CO_2 price forecast. Those are very aggressive assumptions that when taken into context suggests that it would not be prudent to incorporate large scale adoption of solar into the Preferred Portfolio at this time given the low likelihood that all of these assumptions will turn out as predicted in the Generation Shift scenario. In general, the CT Portfolio performs well in most scenarios, presents lower non-fuel fixed cost risk, is consistent with ENO’s resource needs, and complements ENO’s existing portfolio. When renewables were added to the CT Portfolio, the renewables did not improve the performance on both a cost and a risk basis in any scenario other than Generation Shift, even under a range of potential outcomes for gas prices and regulation of CO_2.

Risk Assessment

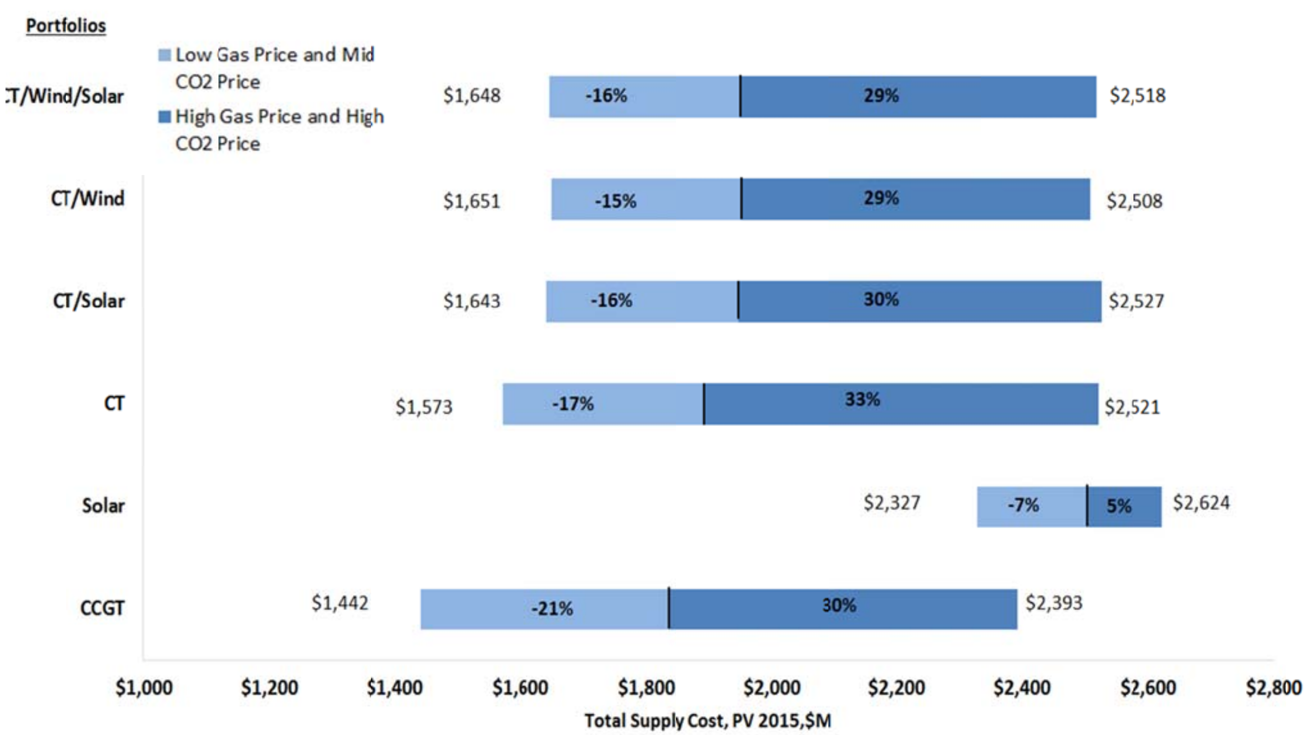
The next and final step in the evaluation of the six portfolios was to perform sensitivity analyses using the reference case assumptions (Industrial Renaissance Scenario) to assess the effects of changes in natural gas prices, carbon prices, and a combination of a change in natural gas prices and carbon prices.

The range of the total supply costs excluding sunk non-fuel costs results by portfolio in the Industrial Renaissance Scenario is provided in the following three figures.

Figure 19: Reference - IR Scenario Sensitivity: Natural Gas (PV $2015, $M)

Figure 20: Reference IR Scenario Sensitivity: CO_2 (PV \$2015, \$M)

Figure 21: Reference - IR Scenario Sensitivity: Natural Gas and CO_2 (PV \$2015, \$M)



Results of the sensitivity assessment indicate that while the Solar Portfolio is less volatile when faced with a change in gas price, CO_2 price, or the combination of natural gas price and CO_2 price, it is significantly more costly than the other portfolios. This is a result of the Solar Portfolio's higher incremental fixed costs, relative to the other five portfolios, due to the requirement to add many times more Solar capacity than conventional alternatives in order to overcome the lower capacity credit available to solar resources. The CCGT and the CT portfolios are similarly affected by changes in gas price assumptions. However, in comparison to the CT Portfolios, the CCGT is relatively less affected by changes in CO_2 price assumptions. It is important to note that implicit in the sensitivity analysis of the CCGT portfolio selected by AURORA is that regardless of whether gas or CO_2 prices are higher or lower than the reference case assumptions, because CCGT resources come with higher non-fuel fixed costs than CT resources, ENO will be relying on the market price for excess energy generating by the CCGT resource exposing ENO's customers to unnecessary risk.

Portfolio Design: Stakeholder Input Case

Due to the changes that were filed September 18, 2015 and the creation of the Stakeholder Input Case, the differences in portfolio design are documented below.

SEPTEMBER 18, 2015 REFRESH

Total supply cost was recalculated to account for the changes in capacity purchases that resulted from the Union reallocation. In addition, three demand response programs were added to the Industrial Renaissance portfolio. Below is the total supply cost for the Industrial Renaissance scenario that reflects the September 18, 2015 changes. Details on the analysis performed on the three demand response programs can be found in the Demand Side Management supplement.

Figure 22: CT Portfolio Load and Capability after September 18, 2015 Update (IR Scenario)

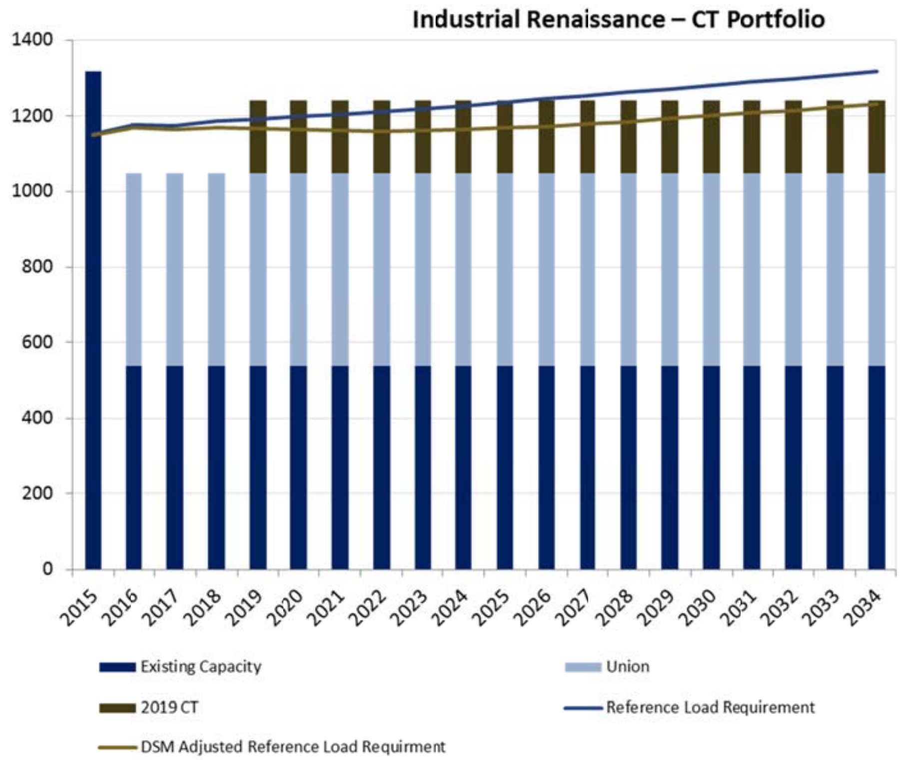
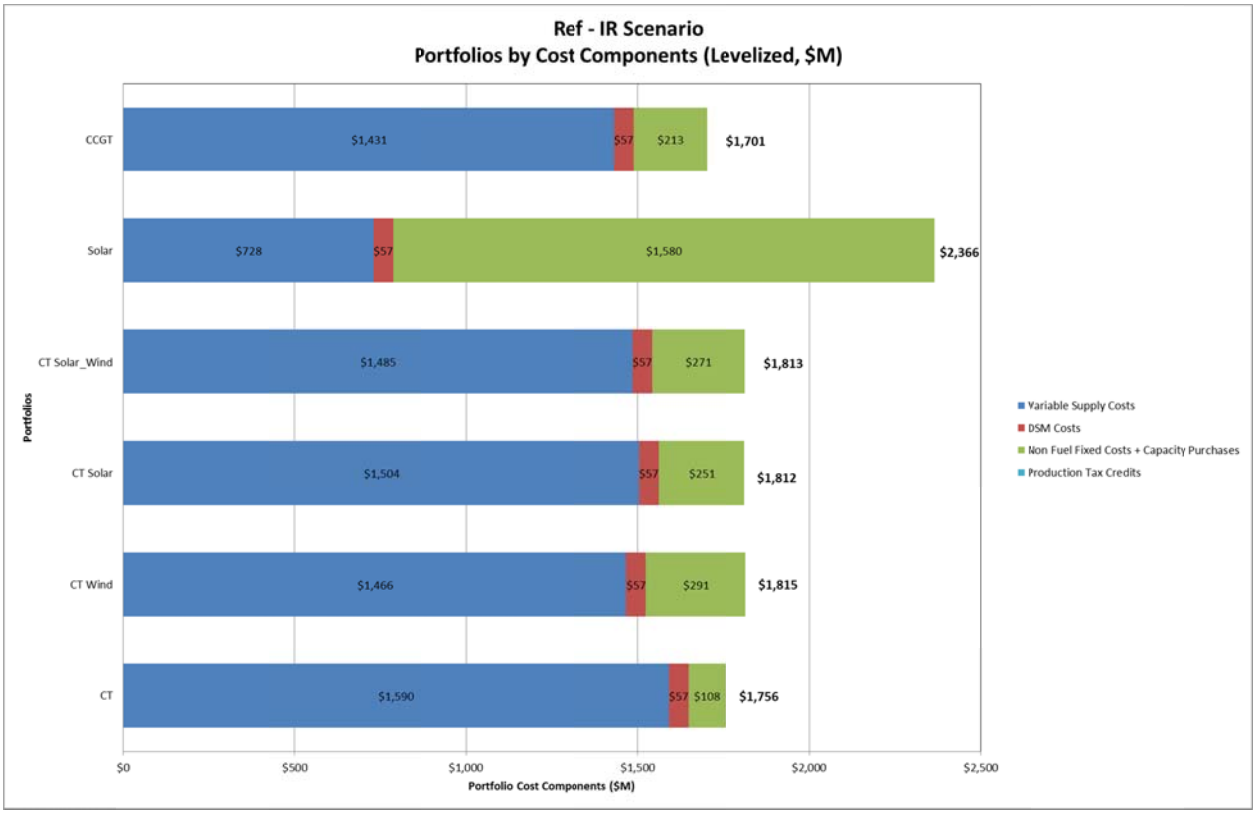


Figure 23: Total Supply Costs Excluding Sunk Non-Fuel Fixed Costs in the Industrial Renaissance Scenario After September 18, 2015 Refresh



STAKEHOLDER INPUT CASE CHANGES

ENO also created a Stakeholder Input Case scenario using the assumptions outlined in Section 2. Once established, ENO ran six additional AURORA simulations for each of the portfolios derived from the same market modeling and manual portfolio design process established earlier in this report. Additional analysis was also done in the selection of DSM programs from the Potential Study. This analysis consisted of determining the optimal implementation year of three demand response programs based on dynamic pricing and load control as well as a trailing benefits assessment of programs initially shown not to breakeven. If the residual benefits of these programs that extended beyond the evaluation period resulted in the programs becoming cost effective, they were added to the portfolio. All six portfolios under the Stakeholder Input Case contain a total of 19 DSM programs listed in Table 25 below. More information on the DSM analysis can be found in the DSM supplement.

Table 24: Portfolio Design Mix – Installed Capacity

Design Mix – Installed Capacity						
	AURORA Capacity Expansion Portfolios		Alternative Portfolios			
	CCGT Portfolio	Solar Portfolio	CT Portfolio	CT/Solar Portfolio	CT/Wind Portfolio	CT/Wind/ Solar Portfolio
DSM Programs	19 Programs	19 Programs	19 Programs	19 Programs	19 Programs	19 Programs
CCGTs	450	0	0	0	0	0
CTs	0	0	250	250	250	250
Solar	0	1200	0	100	0	50
Wind	0	0	0	0	100	50

Table 25: Selected DSM Programs for All Portfolios under Stakeholder Input Case

Sector	Program Name	DSM Program #
Commercial	Commercial Prescriptive & Custom	DSM 1
Commercial	Retro Commissioning	DSM 4
Commercial	Commercial New Construction	DSM 5
Commercial	Data Center	DSM 6
Industrial	Machine Drive	DSM 7
Industrial	Process Heating	DSM 8
Industrial	Process Cooling and Refrigeration	DSM 9
Industrial	Facility HVAC	DSM 10
Industrial	Facility Lighting	DSM 11
Industrial	Other Process/Non-Process Use	DSM 12
Residential	Residential Lighting & Appliances	DSM 13
Residential	ENERGY STAR Air Conditioning	DSM 15
Residential	Efficient New Homes	DSM 18
Residential	Multifamily	DSM 19
Commercial	Non-Residential Dynamic Pricing	DSM 3
Residential	Direct Load Control	DSM 22
Residential	Dynamic Pricing	DSM 23
Residential	Water Heating	DSM 20
Residential	Pool Pump	DSM 21

Figure 24: Cumulative Load Reduction from All DSM Programs (MW)

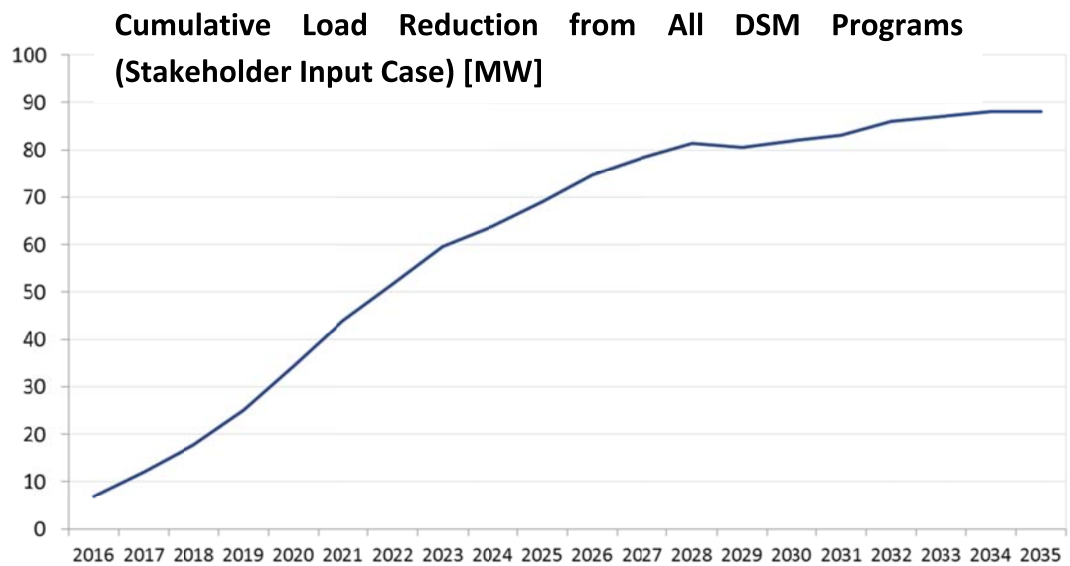


Figure 25: Stakeholder Input Case Scenario CT Portfolio

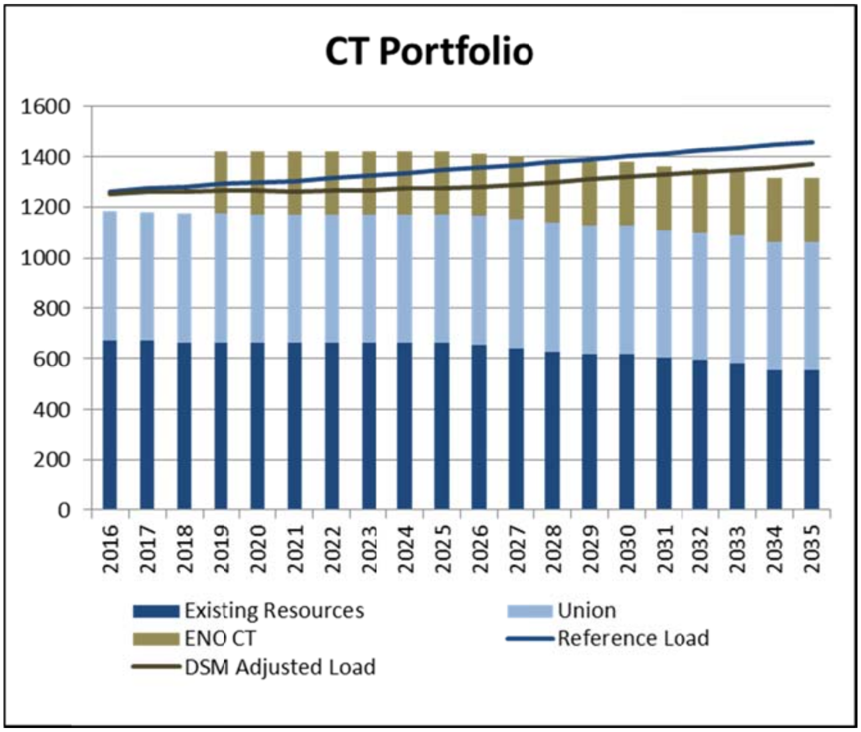


Figure 26: Stakeholder Input Case Scenario CT/Wind Portfolio

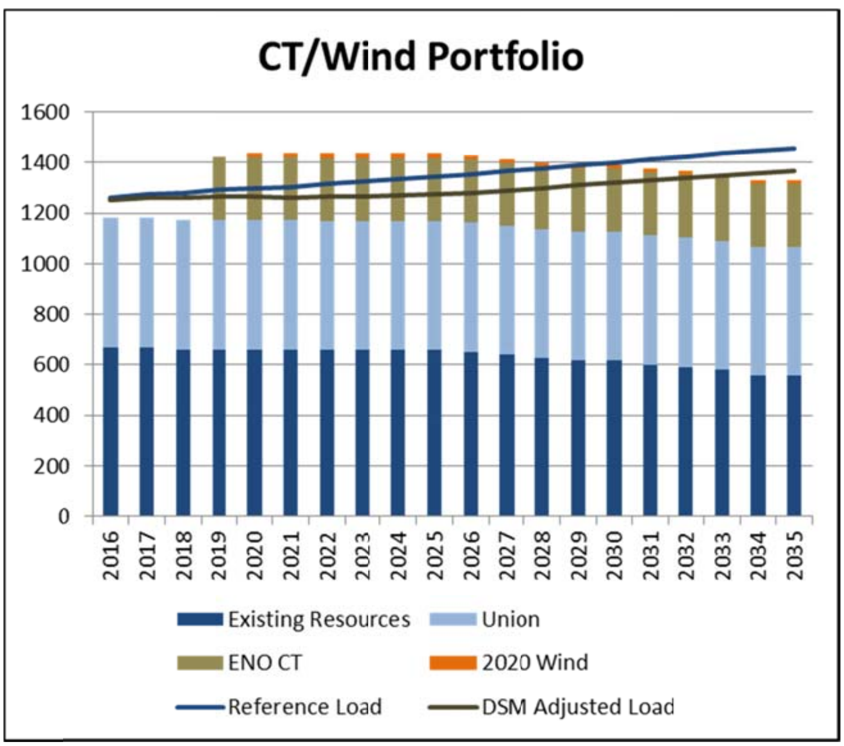


Figure 27: Stakeholder Input Case Scenario CT/Solar Portfolio

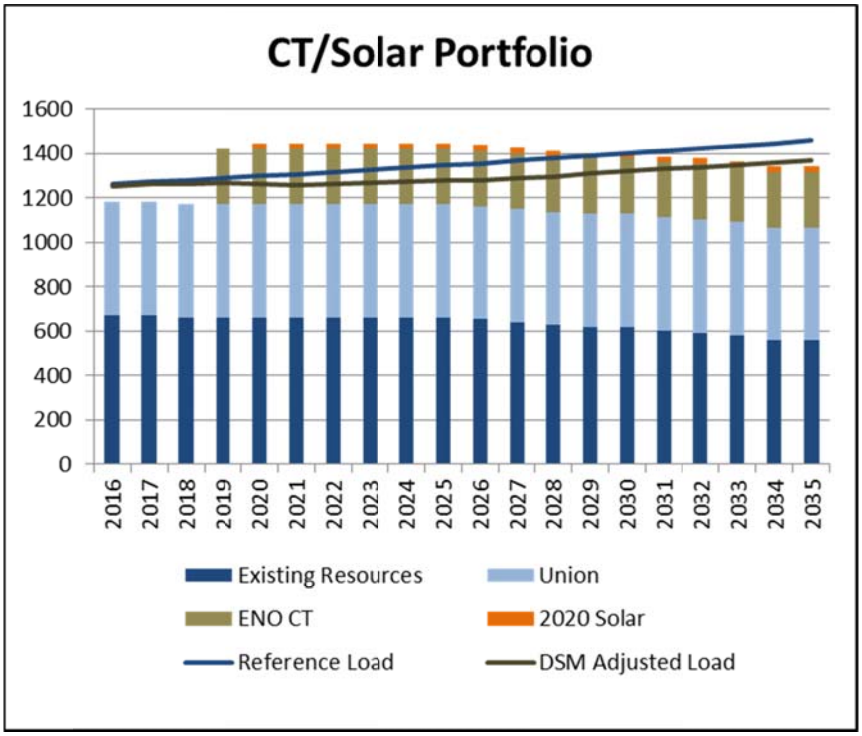


Figure 28: Stakeholder Input Case Scenario CT/Solar/Wind Portfolio

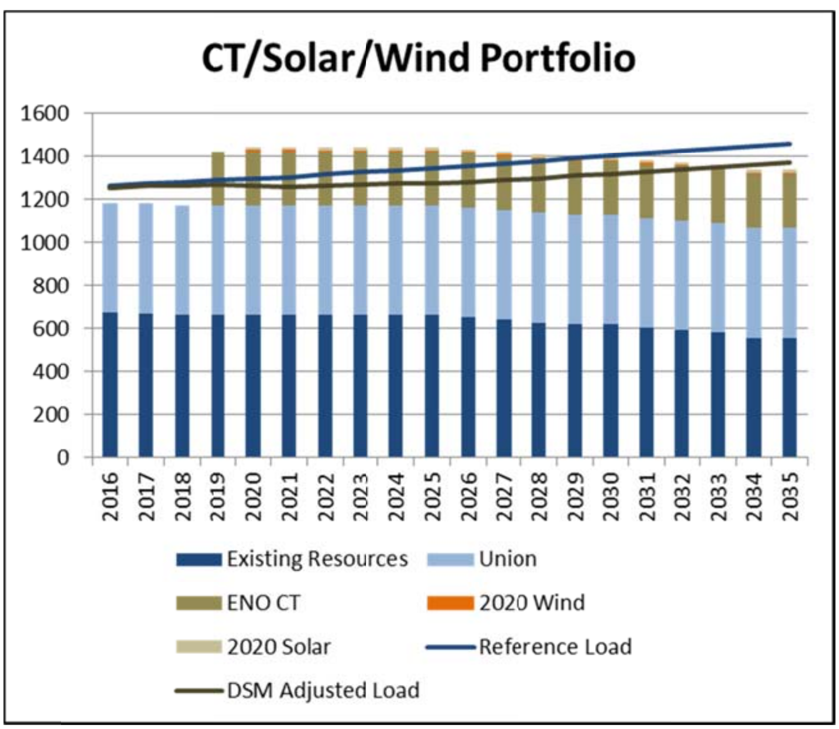


Figure 29: Stakeholder Input Case Scenario CCGT Portfolio

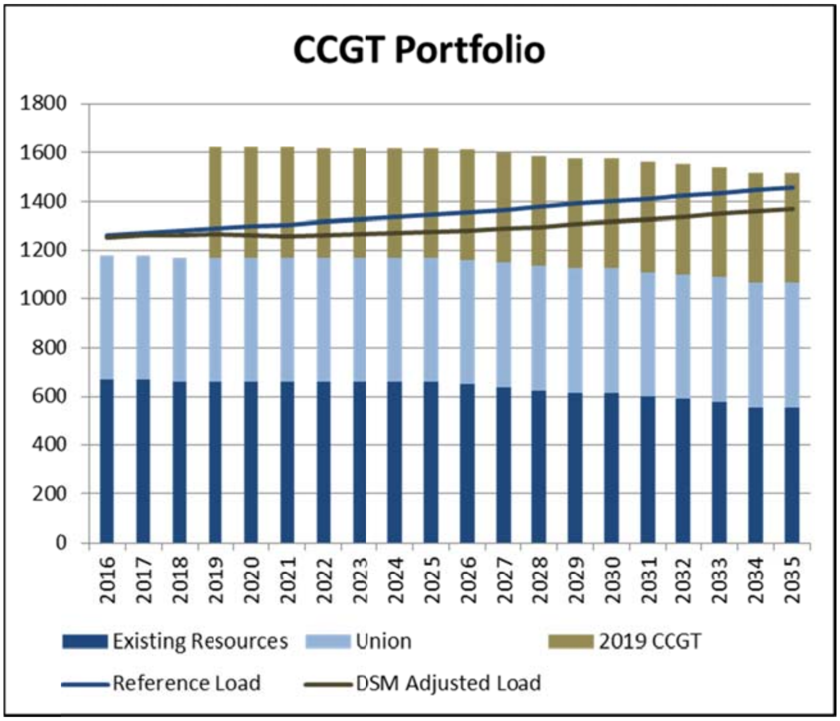


Figure 30: Stakeholder Input Case Scenario Solar Portfolio

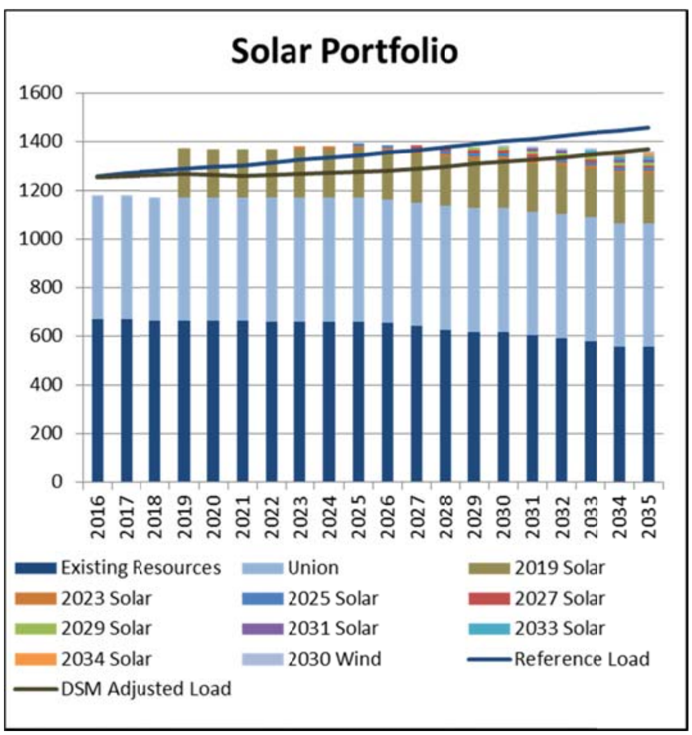


Figure 31 below shows the total supply costs of all six portfolios in the Stakeholder Input case. The CT portfolio is the least expensive while the Solar portfolio is the most expensive.

Figure 31: Total Supply Costs Excluding Sunk Non-Fuel Fixed Costs in the Stakeholder Input Case

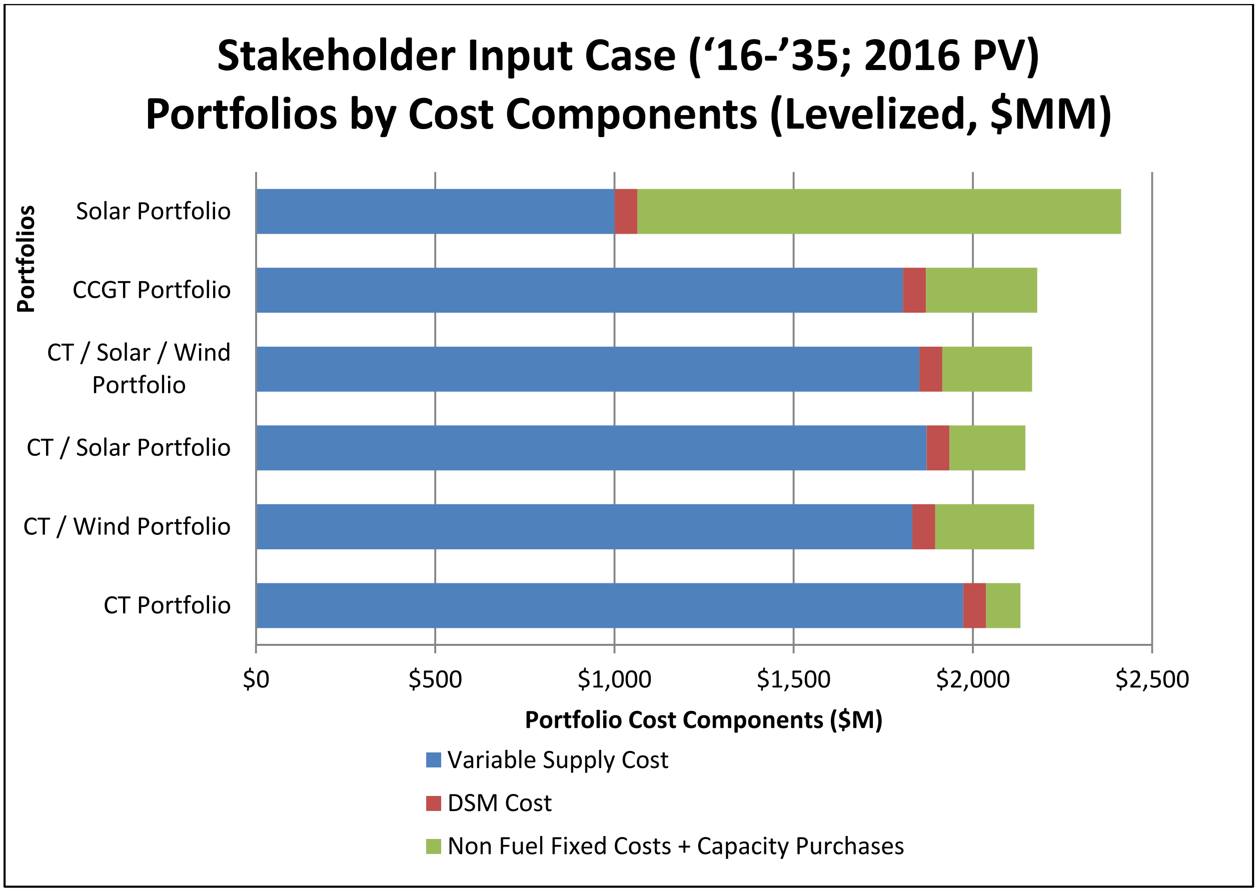


Table 26: Total Supply Cost Portfolio Rankings for Stakeholder Input Case

Total Supply Cost Portfolio Rankings for Stakeholder Input Case		
Portfolios	**Total Relevant Supply Cost Levelized Real ($MM)**	**Ranking**
Solar	$2,413	6
CCGT	$2,180	5
CT Solar_Wind	$2,165	3
CT Solar	$2,146	2
CT Wind	$2,171	4
CT	$2,132	1

Summary of Findings and Conclusions

In summary, ENO reached the following conclusions regarding portfolio design and analytics in the 2015 IRP that form the basis for development of the Preferred Portfolio:

- Supply-side economics were consistent with technology screening analysis.

- Some level of DSM was economic in every scenario.

- At prevailing installed costs as determined by independent third party expert analysis retained by ENO, renewables are not economic under most assumptions. Renewable resources depend on the confluence of high gas and carbon prices and the continuation of subsidies in order to be economic relative to CT and CCGT resources. Moreover, renewables do not provide a comparable amount of capacity as conventional forms of generation, further eroding their economics.

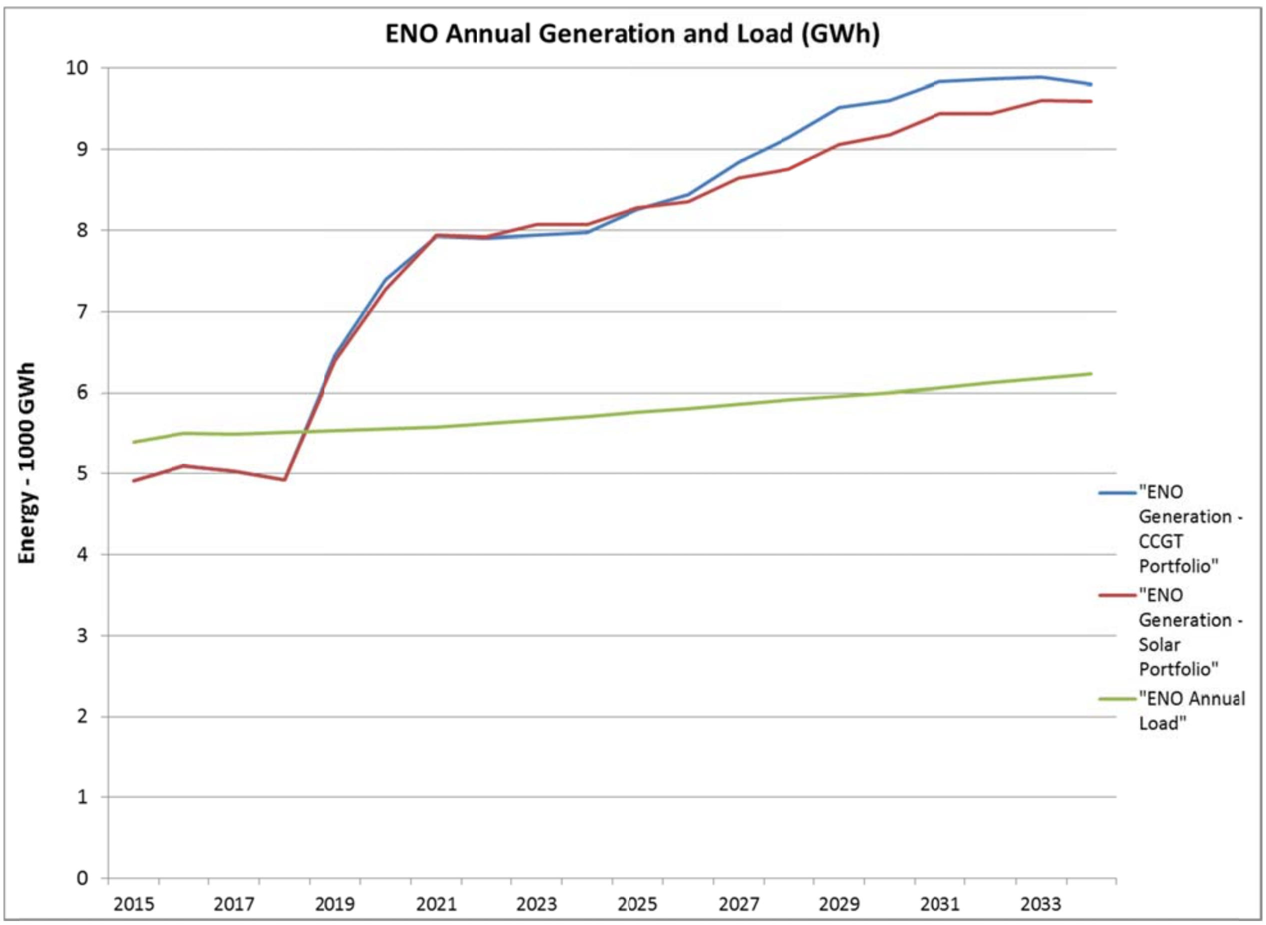
- The AURORA CCGT Portfolio performs well across most scenarios and ranks higher on a total cost basis than the other portfolios. However, ENO's existing portfolio is expected to have adequate Base Load and Core Load Following capacity following the addition of the Council approved Union resource. The CCGT Portfolio has more risk than the CT Portfolios because ENO does not need the energy expected to be produced by those resources, and because CCGT resources have higher fixed costs it would leave ENO and its customers dependent on uncertain potential variable cost savings in the MISO market.

- The CT Portfolio performs well in most scenarios and although it is not the lowest total supply cost portfolio, it has lower risk and is consistent with ENO's resource needs as compared to the other portfolios.

- As show in Figure 32 below, the CCGT portfolio (which is the lowest cost portfolio in the Industrial Renaissance, Business Boom, and Distributed Disruption Scenarios) and the Solar Portfolio (which is the lowest cost portfolio in the Generation Shift Scenario) results in an excess of energy generation in comparison to ENO's projected load requirements. A surplus of energy has a high degree of risk as it exposes ENO to a volatile energy market where it is uncertain that ENO will receive energy revenues sufficient to justify the higher fixed cost.

- In contrast, the CT portfolio presents less risk while providing good economic performance. The CT portfolio performed similarly to the CCGT portfolio in the sensitivity analyses, and its performance did not improve significantly with the addition of renewable technologies. Moreover, the CT has the lowest non-fuel fixed cost in comparison to the other portfolios as indicated in Figure 31.

Figure 32: ENO's Solar and CCGT Portfolios' Annual Generation vs. ENO's Annual Reference Load



SECTION 5: PREFERRED PORTFOLIO & ACTION PLAN

Preferred Portfolio

The IRP process resulted in the identification of a Preferred Portfolio that represents ENO's best available strategy for meeting customers' long-term power needs at the lowest reasonable supply cost, while considering reliability and risk. The Preferred Portfolio is based on the following assumptions:

- In order to reliably meet the power needs of customers at the lowest reasonable cost, ENO will maintain a portfolio of generation resources that includes the right amount and types of long-term capacity resources.

    - With respect to the amount of capacity, ENO must maintain sufficient generating capacity to meet its peak load plus a planning reserve margin. ENO will continue to plan to a 12% reserve margin.

    - With respect to the type of capacity, ENO's supply role needs include primarily peaking and reserve resources following planned additions such as the Council approved transaction to acquire the Union resource. As such, ENO seeks to add modern, proven and highly reliable CT resources consistent with those needs.

- ENO will continue to meet the bulk of its reliability requirements with either owned assets or long-term PPAs. The emphasis on long-term resources mitigates exposure to capacity price volatility and ensures the availability of resources sufficient to meet long-term resource needs.

- A portion of ENO's near-term resource needs may be met through a limited reliance on short-term power purchase products including zonal resource credits available through the MISO capacity market; to the extent these are economically available in consideration of risk.

- Some level of DSM is considered economically attractive over the long-term, but DSM presents ratemaking and policy issues that must be addressed in connection with the adoption of such programs. A variety of factors, many of which are highly uncertain, will affect the amount of DSM that can and will be achieved over the planning horizon.

Table 27: ENO Preferred Portfolio of DSM Programs

Sector	Program Name	DSM Program #
Commercial	Commercial Prescriptive & Custom	DSM 1
Commercial	Retro Commissioning	DSM 4
Commercial	Commercial New Construction	DSM 5
Commercial	Data Center	DSM 6
Industrial	Machine Drive	DSM 7
Industrial	Process Heating	DSM 8
Industrial	Process Cooling and Refrigeration	DSM 9
Industrial	Facility HVAC	DSM 10
Industrial	Facility Lighting	DSM 11
Industrial	Other Process/Non-Process Use	DSM 12
Residential	Residential Lighting & Appliances	DSM 13
Residential	ENERGY STAR Air Conditioning	DSM 15
Residential	Efficient New Homes	DSM 18
Residential	Multifamily	DSM 19
Commercial	Non-Residential Dynamic Pricing	DSM 3
Residential	Direct Load Control	DSM 22
Residential	Dynamic Pricing	DSM 23
Residential	Water Heating	DSM 20
Residential	Pool Pump	DSM 21

- All nuclear units are assumed to receive license extensions from the Nuclear Regulatory Commission ("NRC") to operate up to 60 years.

- New build capacity, when needed in 2019 and beyond, comes from new CT resources. New build capacity may be obtained through owned resources or long-term power purchase contracts. For the purpose of preparing the IRP, the economics were assumed to be equivalent.

- No new solid fuel or new nuclear capacity is added.

- While renewable resources were not selected as economically attractive relative to conventional gas turbine technology to meet ENO's projected resource needs, ENO is committed to continuing to study and evaluate energy resources that make sense for its customers. Case in point, ENO recently announced plans to conduct a 1 MW solar pilot project that will include utility scale solar generation integrated with battery storage technology. The project is estimated to be in service in mid-2016. Additionally, ENO will conduct an RFP for up to 20 MW of renewable resources to determine the most up to date and accurate state of the market.

The Preferred Portfolio shown in Table 28 includes assumptions regarding future resource additions, such as the Union Power acquisition recently approved by the Council, as well as assumptions regarding implementation of cost-effective DSM programs beyond the programs recently approved by the Council for years 5 and 6 of Energy Smart. The actual resources deployed (including the amount and timing of technology and power purchase products) and DSM implemented, will depend on factors which may differ from assumptions used in the development of the IRP. Such long term uncertainties include, but are not limited to:

- Load growth (magnitude and timing), which will determine actual resource needs;
- The relative economics of alternative technologies, which may change over time;
- Environmental compliance requirements; and
- Practical considerations that may constrain the ability to deploy resource alternatives such as the availability of adequate sources of capital at reasonable cost

There are two overarching points to consider when reviewing the Preferred Portfolio. First, the decision to procure a given resource will be contingent upon a review of available alternatives at that time, including the economics of any viable transmission alternatives available that would be coupled with a purchase of capacity and/or energy. In addition, the decision to procure a specific resource in a specific location must reflect the specific lead time for that type of resource, which will vary by resource type, and the time required for obtaining regulatory approvals. By deferring specific resource decisions until deployment is needed, ENO retains the flexibility to respond to changes in circumstance up to the time that a commitment is made.

Second, a variety of factors, many of which are highly uncertain, will affect the amount of DSM that can and will be implemented over the planning horizon. DSM assumptions, including the level of cost-effective DSM identified through the IRP process, are not intended as definitive commitments to particular programs, program levels or program timing. The implementation of cost-effective DSM requires consistent, sustained regulatory support and approval. ENO's investment in DSM must be supported by a reasonable opportunity to timely recover all of the costs, including lost contribution to fixed cost, associated with those programs. It is important that appropriate mechanisms be put into place to ensure the DSM potential actually accrues to the benefit of customers and that utility investors are adequately compensated for their investment through opportunity to recover lost contributions to fixed cost and earn performance-based incentives.

Table 28: ENO Preferred Portfolio Stakeholder Input Case--Load & Capability 2015-2035 (All values in MW)

Load & Capability 2016—2035																				
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Requirements																				
Peak Load	1,125	1,136	1,143	1,153	1,159	1,163	1,175	1,183	1,193	1,201	1,209	1,220	1,230	1,241	1,251	1,261	1,271	1,281	1,291	1,301
Reserve Margin (12%)	135	136	137	138	139	140	141	142	143	144	145	146	148	149	150	151	153	154	155	156
Total Requirements	1,260	1,273	1,280	1,291	1,298	1,303	1,316	1,325	1,336	1,345	1,355	1,366	1,378	1,390	1,401	1,412	1,424	1,435	1,446	1,457
Resources																				
Existing Resources																				
Owned Resources	642	642	642	642	642	642	641	641	641	641	633	621	608	598	598	585	575	562	539	539
PPA Contracts	11	11	2	2	2	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-
LMRs	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
Identified Planned Resources																				
Union[43]	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510
Other Planned Resources																				46
DSM[44]	7	12	18	25	34	44	52	60	64	69	75	78	81	80	82	83	86	87	88	88
CT	-	-	-	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Market Purchases (Sales)	73	80	91	(156)	(158)	(162)	(156)	(154)	(148)	(144)	(133)	(112)	(90)	(67)	(58)	(33)	(15)	9	42	53
Total Resources	1,260	1,273	1,280	1,291	1,298	1,303	1,316	1,325	1,336	1,345	1,355	1,366	1,378	1,390	1,401	1,412	1,424	1,435	1,446	1,457

[43] Union plant acquisition is completed pending regulatory approvals.
[44] Demand Side Management (DSM) total is grossed up for Planning Reserve Margin (12%) and transmission losses (2.4%).

Rate Effects

The estimated typical bill effects associated with the cost to meet customer's needs through the Preferred Portfolio over the next two decades are modest. Over time, inflation in the broader economy tends to drive prices up for all goods and services, and in general the average annual growth rate in projected customer bills (reflected in the last column in Table 29) during the IRP planning horizon are expected to grow below inflation expectations.

Table 29: ENO Average Residential Customer Electric Bill (Preferred Portfolio)[45]

Projected ENO Residential Customer Bill and Energy Usage				
Customer Segment	Actual 2014 Usage (KWh/mo.)	Actual 2014 Average Monthly Bill	Projected 2035 Usage (KWh/mo.)	Projected 2035 Average Monthly bill
Residential (Legacy)	1,081	$109	1,332	$147
Residential (Algiers)	_	_	1,561	$149

Table 30: Rate Effects – ENO Preferred Portfolio[46]

Projected ENO Average Monthly Customer Bill				
Customer Segment	2016	2026	2035	CAGR[47]
Residential (Legacy)	$110	$127	$147	1.5%
Commercial (Legacy)	$1,095	$1,111	$1,135	0.2%
Industrial (Legacy)	$1,302	$1,151	$1,009	(-1.3%)
Government (Legacy)	$3,377	$3,815	$4,096	1.0%
Residential (Algiers)	$100	$132	$149	2.0 %
Commercial (Algiers)	$628	$836	$922	1.9%
Industrial (Algiers)	$234	$348	$406	2.8%
Government (Algiers)	$1,282	$1,775	$2,050	2.4%

[45] Includes benefits associated with the optimal (cost-effective) level of DSM identified through the DSM Optimization.

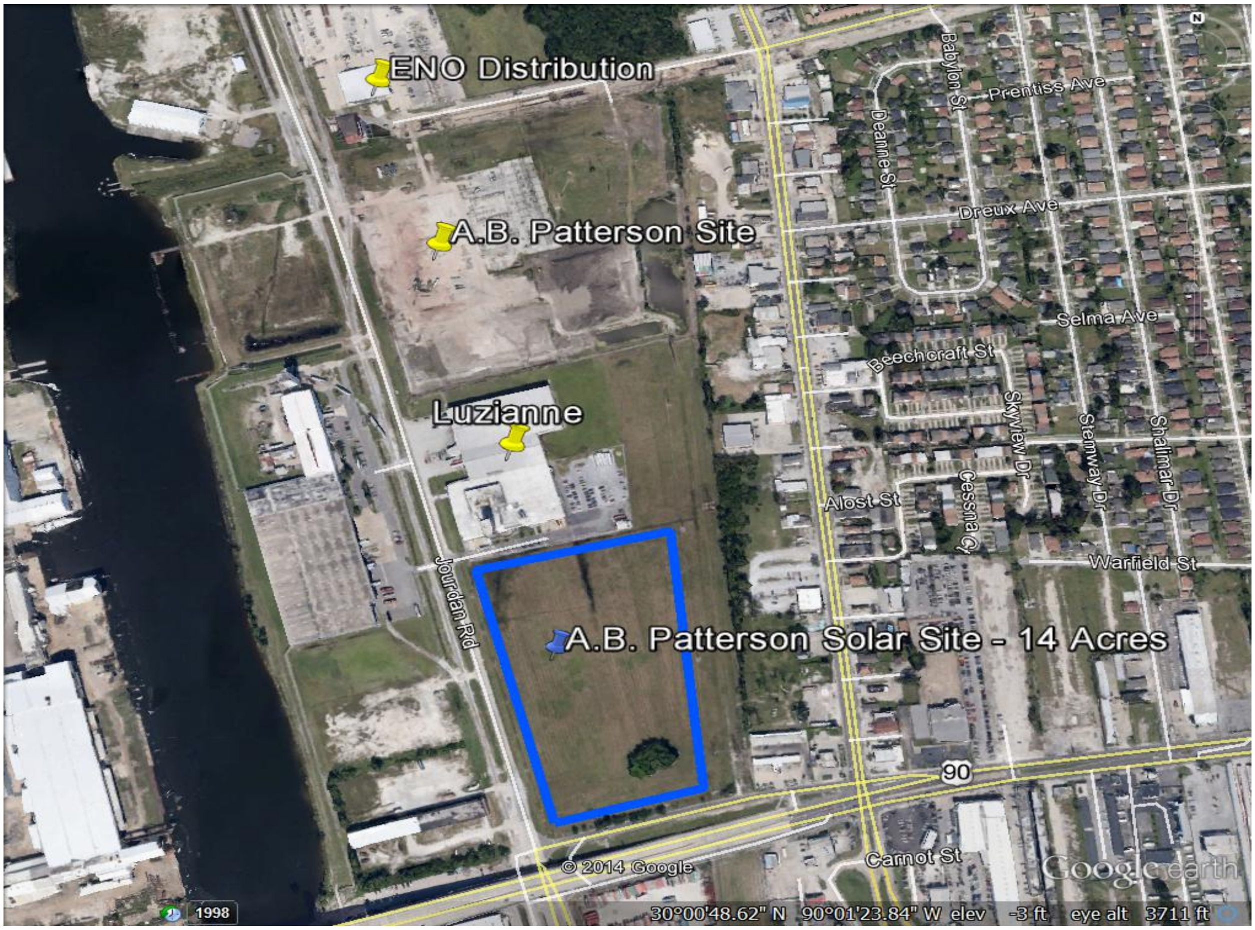
[46] The updated rate effects for the Preferred Portfolio are found in the Updated Assumptions Supplement.

[47] Compound Annual Growth Rate ("CAGR") measures the average annual rate of growth in typical customer bills over the planning horizon.

Solar Pilot

As previously mentioned in the Executive Summary, ENO plans to conduct a 1 MW solar storage pilot project that will integrate solar PV generation and battery storage technology. The pilot project will be constructed within ENO's service territory, specifically, on a plot of land in New Orleans East as shown in Figure 33 below.

Figure 33: Map of ENO Solar Pilot Project



The target in service date is summer 2016.

Stakeholder Input Case

In response to stakeholder and Advisor concerns regarding dated assumptions used in the draft IRP, ENO agreed to perform additional production cost analysis using updated assumptions in support of the Final ENO 2015 IRP. Throughout the IRP process, ENO attempted to the balance the time required to run analysis and move through the IRP process with using the best available information. Notwithstanding, ENO requested more time to run updated cases and thus updated many assumptions based on stakeholder and Advisor concerns. Once the

Stakeholder Input Case was established, ENO ran six additional AURORA simulations for each of the portfolios previously evaluated in the draft IRP. ENO added carbon to the Reference Case and found that there was no significant change in the results. ENO also updated the natural gas assumptions and installed solar cost assumptions in the Stakeholder Input Case. These updates, and the subsequent results of the analysis, substantiated the results of the Draft IRP. The CT Portfolio has the lowest total supply cost in the Stakeholder Input Case.

Action Plan

As part of the planning process, areas of focus necessary to continue moving in a direction that supports implementation of the Preferred Portfolio for ENO have been highlighted in Table 31 below. As discussed above, ENO's projected near-term resource needs create both challenges and opportunities. Planning to address these challenges is already underway as outlined in the 2015 IRP; however, additional steps are necessary to ensure those resources are implemented in a timely and cost-effective manner. The ENO 2015 Preferred Portfolio will modernize ENO's generating fleet, contribute to ENO's long term resource needs and facilitate investment in regional generation, transmission and distribution resources to ensure ENO is capable of continuing to provide safe and reliable service to its customers at the lowest reasonable cost. The Action Plan provided below sets forth the framework for the ongoing planning process. ENO will continue to work with the Council to solidify the details of this plan as and when appropriate based on the outcome of the IRP proceeding.

Recap: 2012 Action Plan

Table 29: Recap of 2012 Action Plan

<table>
<tr><th>Category</th><th>Action to be taken</th></tr>
<tr><td>Supply-side Alternatives</td><td>➢ Continue to take steps necessary to support new generation in DSG to support eventual deactivation of aging fleet.
➢ Evaluate costs and benefits of investing in existing resources in order to support reliable operation beyond deactivation date.</td></tr>
<tr><td colspan="2"><u>2015 Update</u>
➢ Completed PPA with Entergy Louisiana for a share of Ninemile 6.
➢ Conducted an economic analysis comparing the cost of extending the life of Michoud Units 2 and 3 to deactivating each unit and deploying new resources.
➢ Submitted an Attachment Y request to MISO to study the impact on the transmission system associated with deactivation of Units 2 and 3.</td></tr>
<tr><td>Demand-side Alternatives</td><td>➢ Develop program and implementation plan for next phase of DSM for New Orleans.</td></tr>
</table>

	➢ File plan with the Council by March 31, 2013 ➢ Implement programs beginning April 1, 2014
2015 Update ➢ The first phase of EnergySmart programs were extended until March 31, 2015 ➢ The second phase of EnergySmart programs were implemented on April 1, 2015	
MISO Transition	➢ Monitor MISO's resource adequacy requirements as the Entergy System integration process moves forward. ➢ Conduct evaluation of MISO baseload hedging entitlements and impact on production costs.
2015 Update ➢ Filed first Post Integration Annual Monitoring report as required by the Council on May 11, 2015 ➢ Completed evaluation of the adequacy of ENO's baseload hedging entitlements	
Area Planning	➢ Refine supply plan based on experience in MISO. ➢ Integrate MISO's MTEP into the IRP planning process.
2015 Update Completed integration of experience in MISO, including MTEP, into 2015 IRP	

Table 30: ENO 2015 Action Plan

Category	Action to be taken
Deactivation of Michoud Units 2 and 3	➢ Confirmed Attachment Y deactivation request complete for Michoud 2and 3 pursuant to the MISO tariff. ➢ Units 2 and 3 will be deactivated June 1, 2016 subject to completion of necessary transmission upgrades as required by Attachment Y
Union Power Station	➢ Obtained council approval on November 19, 2015 for ENO purchase of Union Power Block 1 ➢ Transaction scheduled to close in early 2016
ENO Solar Pilot	➢ Construction to begin 1st quarter 2016 ➢ Target in service date Summer 2016
In-region Peaking Generation	➢ Continue development activities and finalize preliminary design and site location ➢ File for Council approval in a timely manner ➢ Target 2019 in service date
Clean Power Plan	➢ Continue to monitor pending litigation of the rule and the status of Louisiana Department of Environmental Quality plan to comply

DSM	➢ Continue implementation and performance monitoring of Council approved programs for EnergySmart Years 5 and 6 through March 2017
Resource Needs	➢ Continue to monitor resource needs (load, customer count, net metering, resource deactivations) and adjust near-term action items plan accordingly
Renewable RFP	➢ Conduct a Renewable RFP to obtain actionable information on the cost and deliverability of renewable resources
Distributed Generation	➢ Evaluate alternative methods for the treatment of DG in the integrated resource planning process for opportunities for improvement
AMI	➢ Entergy is currently considering various future investments to modernize the distribution grid and more fully utilize new technologies ➢ AMI continues to be analyzed and ENO plans to talk further with the City Council and the Advisors regarding potential future AMI investments